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09-AFC-1
DATE MAR 21 2012
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STATE OF CALIFORNIA

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

In the Matter of:	)	Docket No. 09-AFC-1
	)	
Application for Certification	)	
For the Watson Cogeneration Steam	)	
And Electric Reliability Project	)	

SUPPLEMENTAL STAFF FILING REGARDING ADDITIONAL STAFF-PROPOSED ERRATA

California Energy Commission (Energy Commission) staff again thanks the Committee for the opportunity to provide comments on the February 15, 2012 Presiding Member's Proposed Decision (PMPD) for the Watson project. Below, and on the attached Greenhouse Gas and Air Quality sections of the PMPD, staff: (1) recommends some edits that are in addition to staff's comments filed on March 16, 2012, (2) accepts and incorporates Applicant's comments on Conditions of Certification AQ-SC9 and AQ-SC10, and (3) provides suggested language to implement South Coast Air Quality Management District (District) comments, with two exceptions noted below. Staff discussed the suggested language with the District staff and both parties have agreed in principle to the approach. New text is shown in double underline and text to be removed is shown ~~in strikeout~~. Different colors are used for the three sets of recommended changes. Staff notes that the changes recommend in our March 16, 2012 filing are not shown here, but we still request that the Committee consider those changes.

1. Additional Details on the March 16 Comments (red font in attachments)

Staff recommended adding text on page 6.2-3 concerning PSD authority. The suggested language is shown underlined in the Air Quality Section. Staff recommended moving text on the bottom of page 6.2-4 and the top of page 6.2-5 from the Air Quality section to the GHG section. The deleted language is marked in strikeout in the Air Quality Section and inserted into the GHG section, with rewording used to provide appropriate context for this language in the GHG section. Finally, staff recommended moving Finding 10 from the Air Quality Section to the GHG section as Finding 17 (in place of existing PMPD GHG Findings 17, 18 and 19), and these are also shown on the two attachments.

2. Incorporating Applicant Comments (green font in attachment)

On March 19, 2012 filing, the Applicant recommended changing AQ-SC9 to remove the reference to the Quarterly Operation Report and changing AQ-SC10 to remove the phrase "collected on a quarterly basis". Both changes are acceptable to Energy Commission staff and these deletions are shown on the Air Quality section.

3. SCAQMD comments (orange font in attachment)

In a letter dated March 16, 2012 to the Alan Solomon, Energy Commission Project Manager for the Watson Cogeneration Project, the South Coast Air Quality Management District provided a series of recommended changes to the PMPD Air Quality Conditions of Certification only. These changes are needed to align the PMPD's Air Quality Conditions of Certification with the SCAQMD's language from their Final Determination of Compliance, dated March 16, 2011. The SCAQMD letter explains the need for each change. Energy Commission staff marked up the PMPD Air Quality Conditions and discussed the edits with SCAQMD staff by telephone on the morning of March 20, 2012. It was decided to expand the recommended insert to AQ-1 to include the previous sentence from the FDOC, specifically from SCAQMD condition A63.X1. This ensures that the calculation specified therein includes emissions from both the gas turbine and duct burner. The only other change to the SCAQMD recommendations was to delete the last requested change dealing with monitoring pressure drop across the CO catalyst. This needs to be retained as it is required by the FDOC condition D12.X5. Energy Commission staff and District staff have reviewed the attached mark up of the PMPD Air Quality Conditions and agree that they correct any errors and omissions to the conditions.

Date: March 21, 2012

Respectfully submitted,

Jeffery M Ogata

Jeffery M. Ogata
Assistant Chief Counsel

VI. PUBLIC HEALTH AND SAFETY

A. GREENHOUSE GAS (GHG) EMISSIONS

1. Introduction and Summary

The generation of electricity using fossil fuels, such as the natural gas that the Watson Project will consume, produces both "criteria pollutants" and greenhouse gas (GHG) emissions. Criteria pollutants are emissions that are known to adversely affect public health and for which regulatory agencies have established legal "criteria" which limit both the amount of the pollutants that may be emitted as well as the concentrations of the pollutants in the air. The project's criteria pollutant emissions and its compliance with applicable air quality laws are discussed in the **Air Quality** section of this Decision. This section assesses the GHG emissions that are likely to result from the construction and the operation of the project.

The GHGs consist of carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFC), and perflurocarbons (PFC). CO_2 emissions are far and away the most common of these emissions; as a result, even though the other GHGs have a greater impact on climate change on a per-unit basis, GHG emissions are often expressed in terms of "metric tons of CO_2-equivalent" ($MTCO_2e$) for simplicity. (Ex. 200, p. 4.1-89.)

There is general scientific consensus that climate change is occurring and that man-made emissions of GHG, if not sufficiently curtailed, are likely to contribute further to continued increases in global temperatures. (Ex. 200, p. 4.1-90.) Adding GHG to the atmosphere increases the insulating power of the air and thereby traps more heat at and near the earth's surface. The California Legislature has declared that "[g]lobal warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California." (Health & Saf. Code, § 38500; *Id*.)

In December 2009, the U.S. Environmental Protection Agency (EPA) declared that greenhouse gases (GHGs) threaten the public health and welfare of the American people. Regulating GHGs at the federal level is required by the Prevention of Significant Deterioration Program (PSD) that took effect July 1, 2011 for new facilities that exceed an annual emissions rate of 100,000 tons[1] per year (tpy) of carbon dioxide-equivalent (CO2E) emissions, or for additions to an existing facility, like the Watson Project, if they exceed 75,000 tpy CO2E. The Watson Project is estimated to emit about 700,000 tpy CO2, which should be about the same in CO2E. (Ex. 200, p. 4.1-89.)

The SCAQMD is in the process of finalizing Rule 1714 to issue PSD permits for greenhouse gases. As of the date of the most recent evidentiary hearing for this project, the US EPA had not yet approved into the State Implementation Plan (SIP) SCAQMD's Rule 1714, Prevention of Significant Deterioration for GHG, which was adopted by the District on December 10, 2010, nor issued a delegation agreement to the District, which would authorize the District to issue PSD permits for GHG emission sources. (Ex. 203.) Mohsen Nazemi, Deputy Executive Officer for SCAQMD, testified at the evidentiary hearing that until Rule 1714 is approved and a delegation agreement issued, PSD permits for GHG sources would be issued by the US EPA. (11/1/11 RT 14:20–15:1.) Applicant testified that it was in the process of applying for a PSD permit for GHG but had not yet submitted the application. (11/1/11 RT 63:15–19).

In this part of the Decision, we determine that:

- The Watson Project's construction-related GHG emissions will be insignificant;

- The GHG emissions from a power plant's operation should be assessed not by treating the plant as a stand-alone facility operating in a vacuum, but rather in the context of the operation of the entire electricity system of which the plant is an integrated part;

- The GHG emissions from a power plant's operation should be assessed in the context of the state's GHG laws and policies, such as AB 32;

- The Watson Project's operation will be consistent with the state's GHG goals and policies and will help achieve the state's GHG goals, by (1) causing a decrease in overall electricity system GHG emissions; and (2) fostering the addition of renewable generation into the system, which will further reduce system GHG emissions; and

[1] The US EPA promulgated its GHG rules in short tons (2000 pounds per ton). The EPS standard and most other GHG regulations and discussions are in metric tonnes, or 1000 kilograms per tonne. The conversion is 1.10231 short tons per 1 metric tonne.

- The Watson Project's operation will be in compliance with applicable state and federal LORS pertaining to GHG emissions.

2. Policy and Regulatory Framework

As the Legislature stated 35 years ago, "it is the responsibility of state government to ensure that a reliable supply of electrical energy is maintained at a level consistent with the need for such energy for protection of public health and safety, for promotion of the general welfare, and for environmental quality protection." (Pub. Res. Code, § 25001.) Today, as a result of legislation, the most recent aspect of "environmental quality protection" is the reduction of GHG emissions. Several laws and statements of policy are applicable as shown by **Greenhouse Gas Table 1** below.

Greenhouse Gas Table 1
Laws, Ordinances, Regulations, and Standards (LORS)

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule "tailors" GHG emissions to PSD and Title V permitting applicability criteria.
40 CFR Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.
40 CFR Parts 51 and 52	Effective July 1, 2011, a stationary source that emits more than 100,000 TPY of greenhouse gases (GHGs) is also considered to be a major stationary source. A major modification is any project at a major stationary source that results in a significant increase in emissions of any PSD pollutant. A PSD pollutant is a criteria pollutant for which the area is not nonattainment (for SCAQMD, the PSD pollutants are SO2, PM10, PM2.5, NOx, CO, lead, and GHGs).
State	
California Global Warming Solutions Act of 2006, AB 32 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)	This act requires the California Air Resource Board (ARB) to enact standards that will reduce GHG emission to 1990 levels by 2020. Electricity production facilities will be regulated by the ARB.A cap-and-trade program is being developed to achieve approximately 20 percent of the GHG reductions expected by 2020.

Applicable Law	Description
Federal	
40 Code of Federal Regulations (CFR) Parts 51, 52, 70 and 71	This rule “tailors” GHG emissions to PSD and Title V permitting applicability criteria.
California Code of Regulations, tit. 17, Subchapter 10, Article 2, sections 95100 et. seq.	These ARB regulations implement mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)
Title 20, California Code of Regulations, section 2900 et seq.; CPUC Decision D0701039 in proceeding R0604009	The regulations prohibit utilities from entering into long-term contracts with any base load facility that does not meet a greenhouse gas emission standard of 0.5 metric tonnes carbon dioxide per megawatt-hour (0.5 $MTCO_2$/MWh) or 1,100 pounds carbon dioxide per megawatt-hour (1,100 lbs CO_2/MWh)

a. AB 32

The organizing framework for California’s GHG policy is set forth in the California Global Warming Solutions Act of 2006. (Assembly Bill 32, codified in Health & Safety Code, § 38560 et seq. (hereinafter AB 32).) AB 32 requires the California Air Resources Board (“CARB”) to adopt regulations that will reduce statewide GHG emissions, by the year 2020, to the level of statewide GHG emissions that existed in 1990. Gubernatorial Executive Order S-3-05 (June 1, 2005) requires a further reduction, to a level 80 percent below the 1990 GHG emissions, by the year 2050. (Ex. 200, p. 4.1-91.)

The Energy Commission recognizes that meeting the AB 32 goals is vital to the state’s economic and environmental health. CARB staff is developing regulatory language to implement its plan and holds ongoing public workshops on key elements of the recommended GHG reduction measures, including market mechanisms. The Scoping Plan approved by ARB in December 2008 and re-approved on August 24, 2011 builds upon the overall climate policies of the Climate Action Team report and shows the recommended strategies to achieve the goals for 2020 and beyond. The Scoping Plan also includes a strategy to greatly expand use of combined heat and power (CHP or cogeneration) facilities by adding new CHP capacity by 2020. Some strategies focus on reducing consumption of petroleum across all areas of the California economy. Improvements in transportation energy efficiency (fuel economy) and land use planning and alternatives to petroleum-based fuels are slated to provide substantial reductions by 2020. The Scoping Plan includes a 33 percent Renewables Portfolio Standard (RPS), aggressive energy efficiency targets, and a cap-and-trade system that includes the electricity sector. Even more dramatic reductions in electricity sector emissions would likely be required to meet California's 2050 greenhouse gas reduction goal. Facilities under our jurisdiction, such as the Watson Project, must be consistent with these policies. (Ex. 200, p. 4.1-91.)

In addition to AB 32, there are several other important components of the state GHG policy and regulatory structure.

b. Renewable Portfolio Standard

California statutory law requires the state's utilities to provide at least 20 percent of their electricity supplies from renewable sources by the year 2020. (Pub. Util. Code, § 399.11 et seq.) Recent Gubernatorial Executive Orders increase the requirement to 33 percent and require CARB to adopt regulations to achieve the goal. (Governor's Exec. Orders Nos. S-21-09 (Sept. 15, 2009), S-14-08 (Nov. 17, 2008).) (Ex. 200, pp. 4.1-91 - 92.)

c. Emissions Performance Standard

Senate Bill (SB) 1368 of 2006, and regulations adopted by the Energy Commission and the Public Utilities Commission pursuant to the bill, prohibit utilities from entering into long-term commitments with any facilities having a capacity factor greater than or equal to a 60 percent that exceed an Emission Performance Standard (EPS) of 0.500 metric tonnes of CO_2 per megawatt-hour. This is the equivalent of 1,100 pounds CO_2/MWh. (Pub. Util. Code, § 8340 et seq.; Cal. Code Regs., tit. 20, § 2900 et seq.; CPUC D0701039.) (Ex. 200. p. 4.1-92.)

d. Loading Order

In 2003, the Energy Commission and the CPUC agreed on a "loading order" for meeting electricity needs. The first resources that should be added are energy efficiency and demand response (at the maximum level that is feasible and cost-effective) followed by renewables, distributed generation and combined heat and power (also known as cogeneration) and finally efficient fossil sources and infrastructure development.[2] CARB's AB 32 Scoping Plan reflects these policy

[2] California Energy Commission 2008, *2008 Integrated Energy Policy Report Update*, (IEPR) (CEC-100-2008-008-CMF.)

preferences. (California Air Resources Board, Climate Change Scoping Plan, December 2008.)

e. CEQA Guidelines on GHG Emissions

The California Natural Resources Agency recently amended its Guidelines for Implementation of the California Environmental Quality Act ("CEQA Guidelines") to address greenhouse gas emissions. The Guidelines direct lead agencies "to make a good-faith effort, based to the extent possible on scientific and factual data, to describe, calculate or estimate the amount of greenhouse gas emissions resulting from a project," and permit agencies to "use a model or methodology to quantify greenhouse gases . . .and/or . . . rely on qualitative analysis or performance-based standards." (14 Cal. Code Regs., §15064.4(a).)

The Guidelines set forth three factors for a lead agency to consider, among others, in assessing the significance of impact from GHG emissions and the environment: "(1) The extent to which the project may increase or reduce greenhouse gas emissions as compared to the existing environmental setting; (2) Whether the project emissions exceed a threshold of significance that the lead agency applies to the project; [and] (3) The extent to which the project complies with regulations or requirements adopted to implement a statewide regional or local plan for the reduction or mitigation of greenhouse gas emissions." (*Id.)* While the Guidelines do not specify any threshold of significance for GHGs, they continue to encourage agencies to adopt quantitative thresholds of significance for pollutants through a formal rulemaking process, and the amendments to expressly allow agencies to "consider thresholds previously adopted or recommended by other public agencies or recommended by experts, provided the decision of the lead agency to adopt such a threshold is supported by substantial evidence." (14 Cal. Code Regs., § 15064.7.)

f. Cap-and-Trade Program

Watson will be required to participate in California's greenhouse gas cap-and-trade program. The program is expected to begin in January 2012. This cap-and-trade program is part of a broad effort by the State of California to reduce GHG emissions as required by AB 32. Market participants such as Watson are already required to report their GHG emissions. Once enabling regulations are implemented, they will be required to obtain GHG emissions allowances (and offsets) for those reported emissions by purchasing GHG allowances from the capped market and offsets from outside the AB32 program. As new participants enter the market, and the market cap is ratcheted down over time, GHG emission allowance and offset prices will increase, encouraging innovation by market participants to reduce their GHG emissions. Thus, Watson as a GHG cap-and-trade participant will be consistent with California's landmark AB 32 Program, which is intended to reduce California's GHG emissions to 1990 levels by 2020. (Ex. 200, p. 4.1-95.)

g. Energy Commission Precedent

Implementation of the State and Energy Commission policies discussed above should result in increasing availability and flexibility of renewable generation. Gas-fired power plants such as Watson currently play a role in advancing the State's climate and energy goals by displacing less-efficient generation resources and facilitating the integration of renewables into the system. However, as the Energy Commission observed in its December 2009 Decision on the Avenal Energy Project (08-AFC-01), the ability of gas-fired generation to contribute to the State's climate and energy goals is limited. The availability of renewable generation will increase as new projects are licensed and built and the technology develops. Efficiency and conservation measures have already had a substantial impact on California's energy consumption, and new measures continue to be implemented. We therefore expect that the proportion of gas generation in the state's generation mix will gradually diminish. Accordingly, we must evaluate the consistency of each proposed gas-fired power plant with these policies in order to ensure that we license only those plants which will help to reduce GHG.

In Avenal, the Energy Commission used a three-part test to aid in its analysis of a proposed gas-fired plant's ability to advance the goals and policies described above. Gas-fired plants must:

1. Not increase the overall system heat rate for natural gas plants;

2. not interfere with generation from existing renewable facilities nor with the integration of new renewable generation; and

3. reduce system-wide GHG emissions and support the goals and policies of AB 32.[3]

[3] *Final Commission Decision on the Avenal Energy Application for Certification,* p. 101; [http://www.energy.ca.gov/sitingcases/avenal/documents/index.html]).

While Avenal was decided before the Natural Resources Agency amended its Guidelines to specifically address GHG Emissions, we find the above factors to be consistent with the CEQA Guidelines, particularly the guidance set forth in Title 20 California Code of Regulations, section 15064.4(b)(1) & (3).

Commission staff suggests in the Final Staff Assessment that the Avenal Decision may not be applicable to the Watson Project because it is a combined heat and power (CHP) project intended primarily to serve a refinery, and not a conventional natural gas power plant like Avenal. However, the evidence shows that although the Watson Project's output is primarily intended to facilitate reliable operation of the refinery, it is located in a heavy load pocket and the power it produces will reduce the refinery's demands on the grid. These attributes are consistent with the three Avenal factors. (Ex. 200, p. 4.1-94.)

We now turn to a discussion of whether, and how well, the project would comply with the above-stated policies.

3. Construction Emissions Impacts

Power plant construction involves vehicles and other equipment that produce GHG emissions. The Watson Project's construction emissions are projected at 3,466 metric tons of CO_2-equivalent GHG during the 20-month construction period. (Ex. 200, p. 4.1-95.)

As noted above, the CEQA Guidelines do not specify any threshold of significance for the emission of GHGs during project construction. In Avenal, we observed that draft guidance from CARB staff recommends a "best practices" performance standard for construction emissions of industrial projects, because construction emissions tend to be much smaller than operational emissions. (*See* CARB, Preliminary Draft Staff Proposal, *Recommended Approaches for Setting Interim Significance Thresholds for Greenhouse Gases under the California Environmental Quality Act* (Oct. 24, 2008), p. 9); view online at: **[http://www.arb.ca.gov/cc/localgov/ceqa/meetings/102708/prelimdraftproposal102408.pdf]**.

In 2010, the Bay Area Air Quality Management District (BAAQMD) adopted Air Quality Guidelines which treat GHG emissions from construction in a manner similar to the CARB's Preliminary Draft Staff Proposal. The Guidelines do not specify a threshold of significance for construction-related GHG emissions, but encourage lead agencies "to incorporate best management practices to reduce

GHG emissions during construction, as applicable. Best management practices may include, but are not limited to: using alternative fueled (e.g., biodiesel, electric) construction vehicles/equipment of at least 15 percent of the fleet; using local building materials of at least 10 percent; and recycling or reusing at least 50 percent of construction waste or demolition materials." (*See* BAAQMD, California Environmental Quality Act Air Quality Guidelines, p. 81 approved June 2, 2010); view online at: [**http://www.baaqmd.gov/~/media/Files/Planning%20and%20Research/CEQA/BAAQMD%20CEQA%20Guidelines_May%202011_5_3_11.ashx]**.

The South Coast Air Quality Management District (SCAQMD) approved a different approach to significance of GHG impacts at its December 5, 2008 Board Meeting. Rather than set a threshold for operational emissions, construction emissions are amortized over the life of a project and considered in combination with operational emissions. (*See* Proposal to Adopt Interim CEQA GHG Significance Threshold for Stationary Sources; view online at: **[http://www.aqmd.gov/hb/2008/December/081231a.htm]**).[4] Applying the SCAQMD approach to the Watson Project, GHG emissions from construction, amortized annually over the 40-year life of the project, would be 87 $MTCO_2e$ tons per year, a tiny fraction of a percent of estimated annual GHG emissions from operation.

Nevertheless, we support the application of a performance standard as recommended by CARB, adopted by BAAQMD, and applied in Avenal, which will minimize GHG construction emissions. We find this approach to be consistent with the CEQA Guidelines which permit reliance on performance-based standards. (14 Cal. Code Regs. §15064.4(a)(2).)

We understand that "best practices" include the implementation of all feasible methods to control construction-related GHG emissions. In order to limit vehicle emissions of both criteria pollutants and GHG during construction, Condition of Certification **AQ-SC5** requires the project owner to use: (1) operational measures, such as limiting vehicle idling time and shutting down equipment when not in use; (2) regular preventive maintenance to manufacturer specifications; (3) low-emitting diesel engines meeting federal emissions standards for construction equipment, whenever available; and (4) equipment that meets the latest criteria

[4] SCQAMD has adopted a somewhat complicated tiered approach to determining the threshold of significance for GHG emission from operations (including amortized construction emissions). Essentially, annual emissions greater than 10,000 $MTCO_2e$ per year are deemed potentially significant, though projects found to be consistent with a GHG emissions reduction plan are exempt from a numerical threshold.

emissions standards. These are the current “best practices” for limiting emissions from construction equipment and no party suggested otherwise.

We find that the measures described above to directly and indirectly limit the emission of GHGs during the construction of the Watson Project are in accordance with current best practices. We also note that the GHG emissions anticipated from construction are minimal compared with anticipated operational emissions. GHG emissions will be intermittent and mitigated during that time due to the implementation of the best practices. We therefore find that the GHG emissions from short-term construction activities will not result in a significant adverse impact.

4. Operations GHG Emissions Impacts

a. Watson Project Emissions

The Watson Project will add a nominal capacity of 85 MW by installing a GE 7EA Dry Low NO_x (DLN) combustion turbine with inlet fogging (74 MW summer, 94 MW winter) adjacent to the existing turbines. The project would operate as a base load cogeneration unit and is proposed to be permitted for 8,760 hours of operation per year, with an expected facility capacity factor of greater than 95 percent.

Greenhouse Gas Table 2 shows what the proposed project, as permitted, could potentially emit in greenhouse gases on an annual basis. Electricity generation and fossil-fueled industrial processes GHG emissions are generally dominated by CO_2 emissions from the carbon-based fuels; other sources of GHG are typically small and some (SF_6 and fluorocarbons) also are more likely to be easily controlled or reused/recycled.

The table shows the calculated CO_2 emissions for 4 of the 12 cases in AFC Table 3-2. Case 6 is most representative of the annual maximum of both electricity and steam production, where steam production is equivalent to the maximum water use for steam of 2,100 acre feet per year. Case 1 represents maximum instantaneous electricity output, where Case 4 is a peak steam production case. Case 12 is the high ambient temperature case where CTG output is degraded, such that steam production dominates the metrics of overall thermal efficiency for the entire cogeneration facility, and the “corrected” EPS is the lowest at 0.219 mt/MWhr. The other eight cases all fall within the values calculated for these representative cases.

The proposed project could, on an annual basis, emit approximately 600,000 metric tonnes of CO_2 per year if operated at its maximum permitted level and burning approximately 65 percent natural gas and 35 percent refinery gas. The proposed Watson Project would emit at approximately 0.230 MTCO2/MWh (Case 6), but no more than 0.318 MTCO2/MWh, which would meet the SB 1368 Greenhouse Gas Emission Performance Standard of 0.500 MTCO2/MWh. The new Watson facility would be more GHG-efficient than most existing power plants in the Los Angeles Basin Local Capacity Requirements Area, which has facilities with GHG EPS performance ranging from 0.432 to 0.944 MTCO2/MWh as shown below in **Greenhouse Gas Table 3**.

According to Staff, the cogeneration corrections are imprecise and may not be accurately or consistently included for the cogeneration facilities shown in **Greenhouse Gas Table 3**. A better estimate of GHG impacts from a cogeneration facility like Watson with its use of waste refinery gases, is a direct comparison to the GHG emissions from separate electricity and steam production. The bottom portion of **Greenhouse Gas Table 2** compares total GHG emissions from the Watson Project to “grid” electricity GHG emissions. In the separate electricity production case, we assume 33 percent renewable electricity, with the rest of the separate electricity used coming from modern efficient natural gas-fired combined cycles with a heat rate of 6,940 Btu/kWh HHV (6,310 Btu/kWh LHV). We also include 7.7 percent transmission losses (i.e., you have to generate more to achieve the same on-site delivered electricity that the Watson Project provides). Separate steam production is assumed to be 100 percent natural gas-fired in a 90 percent efficiency boiler. The Watson Project, cogenerating steam and electricity while using waste refinery gas, would produce approximately 18.5 percent less GHGs per year (Case 6) than separate, but still highly efficient production of steam and electricity.

In Case 1 on **Greenhouse Gas Table 2,** the difference in total calculated CO_2 between the Watson Cogeneration Project and the separate production of heat and power is very small. This is due to the fact that steam production is at a minimum and does not include any supplemental duct firing. And, because of low ambient temperatures, CTG fuel input and electricity output are higher, dominating the calculations. However, Case 1 is an outlier and not representative of likely project operations.

The proposed project would increase the available energy and capacity to the electricity system. The Los Angeles Basin Local Capacity Requirements Area would benefit from the incremental increase in energy and capacity provided by the Watson Project. As a project currently located inside a major load pocket, the Watson Project would be likely to provide local reliability support and could facilitate the retirement of other less-efficient power plants. (Ex. 200, pp. 4.1-96 – 4.1-98.)

Greenhouse Gas Table 2
Watson Project, Estimated Potential Greenhouse Gas (GHG) Emissions

Watson Cogeneration			**Case 1**	**Case 4**	**Case 6**	**Case 12**
	Ambient Temperature	Deg F	36	59	59	102
	Fogger Condition:		Off	On	On	On
INPUTS	Natural Gas Total	LHV mmBtu/hr	684.4	627.4	627.4	589.7
	Refinery Gas Total	LHV mmBtu/hr	308.4	298.5	682.1	635.2
	Fuel Totals	LHV mmBtu/hr	992.8	925.9	1309.5	1224.9
OUTPUTS	Steam to Refinery	LHV mmBtu/hr	468.4	465.3	903.2	863.2
	CTG output	LHV mmBtu/hr	321.8	305.4	305.4	284.3
	CTG output	MW net	90.737	85.77	85.263	79.154
METRICS	Efficiency CTG only	%	32.41%	32.98%	32.98%	32.67%
	Heat Rate CTG only (LHV)	Btu/kWh	10,942	10,795	10,859	10,995
	Heat Rate CTG only (HHV)	Btu/kWh	12,036	11,875	11,945	12,095
With Corrections for Cogeneration:						
	Efficiency Cogeneration Facility - correction	%	79.59%	83.24%	92.29%	93.68%
	Heat Rate LHV CTG less Steam - correction	Btu/kWh	5779	5370	4765	4570
	Heat Rate HHV CTG less Steam - correction	Btu/kWh	6,357	5,907	5,242	5,027
GHG OUTPUTS at 8,760 hrs / yr			Natural Gas	Refinery Gas		
	Fuel Emissions Factor (HHV)	lb CO2/mmBtu	116.4	109.45		
		metric tonne/yr	476,793	443,665	603,617	564,881
	Electricity EPS	mt/MWh	0.600	0.590	0.808	0.815
With Corrections for Cogeneration:						
	Electricity EPS less Steam prod. w/spec. EF - corr.	mt/MWh-eq	0.318	0.294	0.230	0.219
SEPARATE PRODUCTION OF ELECTRICITY / STEAM						
Electricity CO2	Baseload NG CC 6,940 HHV Heat Rate	MWh	794,856	751,345	746,904	693,389
		mt/yr	217,564	205,655	204,439	189,791
Steam CO2	90% Efficient Boiler	mt/yr	264,783	263,030	510,572	487,960
CO2	Total- separate	mt/yr	482,347	468,685	715,011	677,751
	Difference	mt/yr	5,554	25,020	111,394	112,871
	% difference		1.2%	5.6%	18.5%	20.0%

(Ex. 200, p. 4.1-97.)

Greenhouse Gas Table 3
Los Angeles Basin Local Capacity Requirements Area, Local Generation Heat Rates and 2010 Energy Outputs

Plant Name	Heat Rate (Btu/kWh)[a]	2010 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Power Plants [d]:	**11,416**	**2,150**	**0.631**
Alamitos (AES)	10,964	879	0.614
El Segundo Power (NRG)	13,052	167	0.705
Huntington Beach (AES)	11,264	932	0.614
Long Beach Generating Station (NRG)	15,917	36	0.938
Redondo Beach (AES)	12,166	135	0.689
CHP facilities [d]:	**9,995**	**4,916**	**0.538**
BP West Coast Product Wilmington Calciner	17,070	217	0.944
Carson Cogeneration Co.	8,777	348	0.433
Civic Center Cogeneration (LA County)	14,494	110	0.832
Corona Cogeneration	9,447	137	0.497
Harbor Cogeneration Company	11,331	21	0.765
San Gabriel (Ripon Cogeneration)	9,511	141	0.506
Oxy-THUMS Long Beach	9,947	356	0.542
Torrance Refinery (ExxonMobil)	14,071	150	0.432
Total Energy Facilities (LACSD)[c]	13,617	135	0.144
UCLA Energy Systems Facility	12,947	286	0.737
Watson Cogen. (Watson West Coast Ref.)	8,862	3,016	0.361
Watson Project	5,027 to 6,357	747[e]	0.219 to 0.318

(Ex. 200, p. 4.1-101)

Notes:
a. Based on the Higher Heating Value or HHV of the fuel.
b. Thermal/electrical partitioning for CHP facilities based upon ARB's Mandatory Reporting procedure.
c. Joint Water Pollution Control Plant; excludes biomass-related emissions based upon ARB's Mandatory Reporting procedure.
d. Central tendency is weighted by annual GWh.
e. Greenhouse Gas Table 3, Case 6.

b. Determining Significance: the Necessity of a System Approach

The process of electricity generation, production, and consumption is unique compared to other industrial projects. As a result, assessing the GHG impacts of power plants requires an approach that is different from the approach taken to analyze any other type of project, whether the analysis is scientific or legal.

In general, when an agency conducts a CEQA analysis of a project such as a proposed factory, shopping mall, or residential subdivision, it does not need to analyze how the operation of the proposed project will affect the larger system or group of factories, malls, or houses in a large multistate region. Rather, such projects are generally analyzed and evaluated on a stand-alone basis. The analysis and evaluation for power plants is, by necessity, different.

California's electricity system – which is actually part of a system serving the entire western region of the U.S., Canada, and Mexico – is large and complex. Hundreds of power plants, thousands of miles of transmission and distribution lines, and millions of points of electricity demand operate in an interconnected, integrated, and simultaneous fashion. Because the system is integrated, and because electricity must be consumed instantaneously in the absence of viable large-scale electricity storage technologies, any change in demand and, most important for this analysis, any change in output from any generation source, is likely to affect the output from all generators. (*Committee Guidance on Fulfilling California Environmental Quality Act Responsibilities for Greenhouse Gas Impacts in Power Plant Siting Applications,* CEC-700-2009-004; hereinafter: "Committee CEQA Guidance".)[5]

The California Independent System Operator (California ISO) is responsible for operating the system so that it provides power reliably and at the lowest cost. Thus the California ISO dispatches generating facilities generally in order of cheapest to operate (i.e., typically the most efficient) to most expensive [i.e., typically the least efficient]). (Committee CEQA Guidance, p. 20.) Because operating cost is correlated with heat rate (the amount of fuel that it takes to generate a unit of electricity), and, in turn, heat rate is directly correlated with emissions (including GHG emissions), *when one power plant runs, it usually will take the place of another facility with higher emissions that otherwise would have operated* (emphasis added). (Committee CEQA Guidance, *2007 IEPR*.)

In sum, the unique way power plants operate in an integrated system means that we must assess their operational GHG emissions on a system-wide basis rather than on a stand-alone basis.

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[5] The report was issued in March 2009 and is found on the Commission website at: **http://www.energy.ca.gov/2009publications/CEC-700-2009-004/CEC-700-2009-004.PDF** .

We now turn to the specifics of the project's operation.

c. The Watson Project's Effects on the Electricity System

(i) Providing Capacity and Ancillary Services

Power plants serve a variety of functions. Most obviously, they provide energy to keep lights shining and machinery working (typically referred to as "load"). But in order to keep the system functioning properly, they must also meet local needs for capacity and for the "ancillary services" of regulation, spinning reserve, non-spinning reserve, voltage support, and black start capability. (Ex. 200, p.4.1- 92.)

As more renewable generation is introduced into the system, gas-fired power plants such as the Watson Project will be necessary to provide intermittent generation support, grid operations support, extreme load and system emergencies support, and general energy support, as well as meet local capacity requirements. At this time, gas-fired plants are better able to provide such services than are most renewables because they can be called upon when they are needed (dispatchable). (Ex. 200, p. 4.1-93.)

(ii) Displacement of More-Costly, Less-Efficient, and Higher-Emitting Power Plants

The trend from 2001 to the present is for electrical energy produced from large, new combined cycle projects (those with a capacity greater than 100 MW and built since 2000) to replace electrical energy produced from aging power plants (those built before 1980). The electrical energy production from aging power plants has declined from 73,131 GWh in 2001 to 6,219 GWh in 2010. At the same time, electrical energy production from new combined cycle plants has increased from 2,730 GWh in 2001 to 71,373 GWh in 2010, essentially replacing the electrical energy produced from the aging power plants. More importantly, at the same time, California's natural gas use efficiency ($MWh_{OUT}/Fuel_{IN}$) in the electricity sector has increased approximately 17 percent over this time. (Ex. 200, p. 4.1-100.)

The proposed Watson Project would have a net heat rate of 5,027 to 6,357 Btu/kWh[6] under normal operating conditions. The heat rate, energy output and GHG emissions of local generation resources near the Watson Project are listed

[6] Based on the High Heating Value (HHV) of the fuel(s) used. HHV is used for all heat rate and fuel conversions to GHG mass emissions that are discussed in this document.

in **Greenhouse Gas Table 3**, above. Compared to most other new and existing units in the Los Angeles Basin Local Capacity Requirements Area, the Watson Project would be more efficient, and emit fewer GHG emissions per MWh of generation. Local generating units with the lowest heat rate or lowest GHG performance factor generally operate more than other units with higher heat rates, as shown by the relative amount of energy (GWh) produced in 2010 from the local units. However, dispatch order can change, or deviate from economic or efficiency dispatch, in any one year or due to other concerns such as permit limits, contractual obligations, local reliability needs or emergencies. (*Id*.)

(iii) Fostering Renewables Integration

Most new renewable generation in California will be wind and solar generated power. But the wind and the sun are not continuous, on-demand resources. As a result, in order to rely on such intermittent sources of renewable-generated power, utilities must have available other, nonrenewable generating resources or significant storage that can fill the gap when renewable generation decreases. Indeed, because of this need for backup generation, or if and when utility-scale storage becomes feasible and cost-effective, nonrenewable generation must increase in order for the state to meet California's RPS and GHG goals. (Ex. 200, p. 4.1-100.)

The Watson Project is not expected to provide flexible, dispatchable or fast ramping[7] power. The Watson Project will be a base-loaded cogeneration facility that operates up to 24 hours per day, 7 days per week in response to steam demands at the refinery. The GE 7EA CTG ramp rate for the proposed cogeneration configuration will be less than 10 MW per minute.[8] However, the Watson Project is not expected to be used in this manner due to the continuous steam needs of the refinery at which it would be located. (Ex. 200, p. 4.1-100.)

As California moves towards an increased reliance on renewable energy, the bulk of renewable energy generation available to and used in California in the near to intermediate future will be intermittent wind generation with widespread

[7] The California ISO categorizes *fast-ramping* as a generator capable of going from lowest power to highest in under 20 minutes, or greater than 10 MW per minute.

[8] Of the 2,821 MW of thermal resources providing Ancillary Services to the California ISO, most (2,441 MW) have ramp rates between 10 and 31 MW/min. The bulk of the resources providing Ancillary Services with ramp rates greater than 10 MW/min (7,141 MW) are hydroelectric facilities (California ISO 2007).

deployment of both utility-scale and small scale distributed solar. To accommodate the increased variability in generation due to increasing renewable penetration, compounded by increasing load variability, control authorities such as the California ISO need increased flexibility from other generation resources such as hydro generation, dispatchable pump loads, energy storage systems, and fast ramping and fast starting fossil fuel generation resources. (Ex. 200, p. 4.1-101.)

These assumptions are conservative in that the forecasted growth in retail sales assumes that the impacts of planned increases in expenditures on (uncommitted) energy efficiency are already embodied in the current retail sales forecast.[9] Staff estimates that as much as 18,000 GWh of additional savings due to uncommitted energy efficiency programs may be forthcoming.[10] This would reduce non-renewable energy needs by a further 12,000 GWh given a 33 percent RPS.

(~~iiii~~iv) Retirement of Generation Using Once-Through Cooling

New resources in the Los Angeles Basin Local Capacity Area like the Watson Project would also be required to provide energy ~~generation capacity~~ in the likely event that facilities utilizing once-through cooling (OTC) are retired. The State Water Resources Control Board (SWRCB) has proposed significant changes to OTC units, which will require the retirement of the OTC generation in the Los Angeles Basin LCA and a replacement of a share of the retired capacity in order to ensure local reliability.[11] Any additional costs associated with complying with the SWRCB regulation would be amortized over a limited revenue stream today and into the foreseeable future. Their energy and much of their dispatchable, load-following capability will have to be replaced, although the energy produced by these facilities is decreasing as they continue to age. These merchant-owned units constitute over 15,000 MW of capacity. See **Greenhouse Gas Table 4.**

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[9] Energy efficiency savings are already represented in the current Energy Commission demand forecast adopted December 2009.

[10] See *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* (CEC-200-2010-001-D, January, 2010), page 2. Table 1 indicates that additional conservation for the three investor-owned utilities may be as high as 14,374 GWh. Increasing this value by 25 percent to account for the state's publicly-owned utilities yields a total reduction of 17,967 GWh.

[11] The OTC policy compliance plans filed by the owners of OTC capacity in the LA Basin LCA indicate that replacement capacity, rather than modifications to existing facilities, will be the method of compliance.

Greenhouse Gas Table 4
Aging and Once-Through Cooling Units: 2010 Capacity and Energy Output

Plant, Unit Name	Owner	Local Reliability Area	Aging Plant?	Capacity (MW)	2010 Energy Output (GWh)	GHG Performance (MTCO2/MWh)
Diablo Canyon 1, 2	Utility	None	No	2,232	18,431	Nuclear
San Onofre 2, 3	Utility	L.A. Basin	No	2,246	13,784	Nuclear
Broadway 3 [a]	Utility	L.A. Basin	Yes	75	38	0.680
El Centro 3, 4 [a]	Utility	None	Yes	132	61	0.344
Grayson 3-5 [a]	Utility	LADWP	Yes	108	162	0.320
Grayson 8ABC[a]	Utility	LADWP	Yes	130	3	0.888
Harbor 1,2 & 5	Utility	LADWP	No	227	172	0.508
Haynes 1, 2, 5 & 6	Utility	LADWP	Yes	1,046	957	0.567
Haynes 8 to 10	Utility	LADWP	No	560	3,436	0.375
Olive 1, 2 [a]	Utility	LADWP	Yes	110	14	0.793
Scattergood 1 to 3	Utility	LADWP	Yes	803	1,015	0.541
Utility-Owned				7,776	38,073	0.460 [c]
Alamitos 1 to 6	Merchant	L.A. Basin	Yes	1,970	879	0.785
Contra Costa 6, 7	Merchant	S.F. Bay	Yes	680	38	0.663
Coolwater 1-4 [a]	Merchant	None	Yes	727	15	0.573
El Segundo 3 & 4	Merchant	L.A. Basin	Yes	670	167	0.619
Encina 1 to 5	Merchant	San Diego	Yes	951	317	0.720
Etiwanda 3 & 4 [a]	Merchant	L.A. Basin	Yes	666	221	0.624
Huntington Beach 1& 2	Merchant	L.A. Basin	Yes	430	491	0.590
Huntington Beach 3 &4	Merchant	L.A. Basin	No	450	440	0.561
Mandalay 1 & 2	Merchant	Ventura	Yes	436	82	0.531
Morro Bay 3 & 4	Merchant	None	Yes	600	93	0.521
Moss Landing 6 & 7	Merchant	None	Yes	1,404	273	0.634
Moss Landing 1 &2	Merchant	None	No	1,080	3,234	0.377
Ormond Beach 1 & 2	Merchant	Ventura	Yes	1,612	117	0.564
Pittsburg 5 to 7	Merchant	S.F.Bay	Yes	1,332	58	0.663
Potrero 3[c]	Merchant	S.F.Bay	Yes	207	429	0.585
Redondo Beach 5 to 8	Merchant	L.A. Basin	Yes	1,343	135	0.621
South Bay 1 to 4[c]	Merchant	San Diego	Yes	696	72	0.611
Merchant-Owned				15,254	7,062	0.560 [d]
Total In-State OTC				23,030	45,135	

Notes:
a. Units are considered “aging” but are not once-through cooled.
b. Unit 7 is considered “aging” but is not once-through cooled.
c. Retired.
d. GHG performance central tendency is weighted by GWh.

(Ex. 200, p. 4.1-105.)

Of this, much but not all of the capacity and energy are in local reliability areas, requiring a share them to be replaced – absent transmission upgrades – by plants located in the same local reliability area. (Ex. 200, p. 4.1-105.)

New generation resources that can either provide local support or energy will emit significantly less GHGs than existing OTC natural gas generation. Existing aging and OTC natural gas generation averages 0.6 to 0.7 MTCO2/MWh, which is less efficient and higher GHG emitting, than a new, natural gas/refinery gas-fired turbine project like the Watson Project. A project located in a coastal load pocket, like the Los Angeles Local Reliability Area, would more likely provide local reliability support as well as facilitate the retirement of aging and/or OTC power plants. The Watson Project would contribute to meeting the goal of replacing facilities that use once through cooling.

We therefore find that GHG emissions from operation activities will not have a significant environmental impact.

5. The Role of New Natural Gas Power Plants

At present, the California electricity system needs new efficient gas-fired generation to displace and replace less efficient generation, and to help integrate additional intermittent renewable generation. But as new gas plants are built to meet those needs, the system will change; moreover, the specific location, type, operation, and timing of each plant will be different. As a result, each plant will have somewhat different impacts. Furthermore, future implementation of efficiency and demand response measures, and new technologies such as storage, smart grid, and distributed generation, may also significantly change the physical needs and operation of the electrical system. It is therefore reasonable to assume that at some point in the future there will be a decrease in the need for additional gas-fired generation. Therefore, we cannot and should not continue adding gas-fired plants *ad infinitum.* Rather, we will analyze each such project in light of the goals and policies discussed above.

In this case, the evidence establishes that the Watson Project will not increase the system heat rate as it has a lower heat rate than many of the generators in the region it would serve. It will support, rather than interfere with, existing and new renewable generation. Finally, it will reduce system-wide GHG emissions and otherwise support the goals of AB 32. We find the proposed project is consistent with state energy policy, and will help the state achieve its renewable energy goals.

6. Cumulative Impacts

Cumulative impacts are defined as “two or more individual effects which, when considered together, are considerable or . . . compound or increase other environmental impacts” (CEQA Guidelines § 15355). “A cumulative impact consists of an impact that is created as a result of a combination of the project evaluated in the EIR together with other projects causing related impacts” (CEQA Guidelines § 15130[a][1]). Such impacts may be relatively minor and incremental, yet still be significant because of the existing environmental background, particularly when one considers other closely related past, present, and reasonably foreseeable future projects.

Air quality impacts are, by their very nature, cumulative. The evidence shows that the project alone would not be sufficient to have a significant impact on global climate. However, it would emit greenhouse gases and therefore has been analyzed for its potential contribution to a cumulative impact in the context of existing GHG regulatory requirements and GHG energy policies. We find that the Watson Project’s contribution would not be cumulatively considerable or significant.

FINDINGS OF FACT

1. The GHG emissions from Watson Project construction are likely to be 3466 $MTCO_2$ equivalent (“$MTCO_2E$”) during the 20-month construction period.

2. There is no numerical threshold of significance under CEQA for construction-related GHG emissions.

3. The three-part test used in Avenal (08-AFC-01) is consistent with the CEQA Guidelines, particularly the guidance set forth in Title 20 California Code of Regulations, section 15064.4(b)(1) & (3).

4. Construction-related GHG emissions will be less than significant if they are controlled with best practices.

5. The project will use best practices to control its construction-related GHG emissions.

6. State government has a responsibility to ensure a reliable electricity supply, consistent with environmental, economic, and health and safety goals.

7. California utilities are obligated to meet whatever demand exists from any and all customers.

8. The maximum annual CO_2 emissions from the Watson Project's operation burning 65 percent natural gas and 35 percent refinery gas will be 600,000 $MTCO_2E$, which constitutes an emissions performance factor range of 0.23 to 0.318 $MTCO_2E$ / MWh.

9. Under SB 1368 and implementing regulations, California's electric utilities may not enter into long-term commitments with base load power plants with CO_2 emissions that exceed the Emissions Performance Standard ("EPS") of 0.500 $MTCO_2$/MWh.

10. The California Renewable Portfolio Standard (RPS) requires the state's electric utilities obtain at least 33 percent of the power supplies from renewable sources, by the year 2020.

11. California's power supply loading order requires California utilities to obtain their power first from the implementation of all feasible and cost-effective energy efficiency and demand response, then from renewables and distribution generation, and finally from efficient fossil-fired generation and infrastructure improvement.

12. Even as more renewable generation is added to the California electricity system, gas-fired power plants will be necessary to meet local capacity requirements and to provide intermittent generation support, grid operations support, extreme load and system emergencies support, and general energy support.

13. There is no evidence in the record indicating that construction or operation of the Watson Project will be inconsistent with the loading order.

14. The Watson Project will have a heat rate of 5,027 to 6,357 Btu/kWhr.

15. The Watson Project will displace generation from less-efficient (i.e., higher-heat-rate and therefore higher-GHG-emitting) power plants in the region.

16. The Watson Project's operation will reduce overall GHG emissions from the electricity system.

17. Since issuance of the FDOC, federal regulation of GHG emissions has become applicable to Watson. Accordingly, Watson is required to obtain a PSD permit for GHG emissions.

~~18. Intermittent solar and wind generation will account for most of the installation of renewables in the next few decades.~~

~~19. The Watson Project's operation will foster the addition of renewable generation into the electricity system by reducing grid demand from the refinery, which will further reduce system GHG emissions.~~

~~20. The addition of some amount of efficient, dispatchable, natural-gas-fired generation will be necessary to integrate renewables into California's electricity system and meet the state's RPS and GHG goals, but the amount is not without limit.~~

CONCLUSIONS OF LAW

1. The Watson Project's construction-related GHG emissions will not cause a significant environmental impact.

2 The Watson Project's operational GHG emissions will not cause a significant environmental impact.

3. The Watson Project's operation will help California utilities meet their RPS obligations.

4. The Watson Project operation will be consistent with California's loading order.

5. The Watson Project operation will foster the achievement of the GHG goals of AB 32 and Executive Order S-3-05.

6. The GHG emissions of any power plant must be assessed within the system on a case-by-case basis.

7. The Watson Project will not increase the overall system heat rate for natural gas plants.

8. The Watson Project will not interfere with generation from existing renewables or with the integration of new renewable generation.

9. The Watson Project will reduce system-wide GHG emissions.

10. Any new natural-gas-fired power plant that we certify must:
    a) not increase the overall system heat rate for natural gas plants;
    b) not interfere with generation from existing renewables or with the

integration of new renewable generation; and

c) have the ability to reduce system-wide GHG emissions.

We find that the Watson Project is consistent with these requirements.

CONDITIONS OF CERTIFICATION

No Conditions of Certification related to greenhouse gas emissions are included. The project owner would comply with mandatory ARB GHG emissions reporting regulations (Cal. Code Regs., tit. 17, Subchapter 10, Article 2, § 95100 et. seq.) and/or future GHG regulations formulated by the U. S. EPA or the ARB, such as GHG emissions cap and trade markets.

B. AIR QUALITY

This section examines the potential adverse impacts of criteria air pollutant emissions resulting from project construction and operation. In consultation with the local air pollution control district, the Commission determines whether the project will likely conform with applicable laws, ordinances, regulations and standards (LORS), whether it will likely result in significant air quality impacts, including violations of ambient air quality standards, and whether the project's proposed mitigation measures will likely reduce potential impacts to insignificant levels. (Ex. 200, pp. 4.1-1, 4.1-2.)

The United States Environmental Protection Agency (U.S. EPA) and the California Air Resource Board (CARB) have both established allowable maximum ambient concentrations of air pollutants based on public health impacts, called ambient air quality standards (AAQS). The state AAQS, established by CARB, are typically lower (more stringent) than the federal AAQS, established by the U.S. EPA. The state and federal air quality standards are listed in **Air Quality Table 1**, below. (Ex. 200, p. 4.1-9.)

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Air Quality Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	California Standard	Federal Standard
Ozone (O_3)	1 Hour	0.09 ppm (180 µg/m^3)	--
	8 Hour	0.07 ppm (137 µg/m^3)	0.075 ppm (147 µg/m^3)
Respirable Particulate Matter (PM10)	24 Hour	50 µg/m^3	150 µg/m^3
	Annual*	20 µg/m^3	--
Fine Particulate Matter (PM2.5)	24 Hour	--	35 µg/m^3
	Annual*	12 µg/m^3	15 µg/m^3
Carbon Monoxide (CO)	1 Hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)
	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
Nitrogen Dioxide (NO_2)	1 Hour	0.18 ppm (339 µg/m^3)	0.100 ppm**
	Annual*	0.030 ppm (57 µg/m^3)	0.053 ppm (100 µg/m^3)
Sulfur Dioxide (SO_2)	1 Hour	0.25 ppm (655 µg/m^3)	0.075 ppm (196 µg/m^3)***
	3 Hour	--	0.5 ppm (1300 µg/m^3)
	24 Hour	0.04 ppm (105 µg/m^3)	--
Lead	30 Day Average	1.5 µg/m^3	--
	Calendar Quarter	--	1.5 µg/m^3
	Rolling 3-mo Ave		0.15 µg/m^3
Sulfates	24 Hour	25 µg/m^3	--
Hydrogen Sulfide (H_2S)	1 Hour	0.03 ppm (42 µg/m^3)	--
Vinyl Chloride (chloroethene)	24 Hour	0.010 ppm (26 µg/m^3)	--
Visibility Reducing Particulates	8 hours	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.	--

* Annual Arithmetic Mean.
**Three-year average of 98th percentile daily maximum 1-hour values, effective April 12, 2010.
*** Effective June 2, 2010, the U.S. EPA established this standard as the 3-year average of the annual 99th percentile of 1-hour daily maximum concentrations.

The federal Clean Air Act[1] requires new major stationary sources of air pollution to comply with federal requirements. The U.S. Environmental Protection Agency (U.S. EPA), which administers the Clean Air Act, has designated all areas of the United States as attainment/unclassifiable (air quality better than the AAQS or unable to determine) or nonattainment (worse than the AAQS) for criteria air pollutants. (Ex. 200, p. 4.1-9.)

There are two major components of federal air pollution law: New Source Review (NSR) for evaluating new sources of pollutants that violate federal standards and Prevention of Significant Deterioration (PSD) to evaluate new sources of pollutants that do not violate federal standards. Prevention of Significant Deterioration (PSD) requires major sources to obtain permits for attainment pollutants. A major source is defined as any one pollutant exceeding 250 tons per year, unless the source is a named PSD category (which the Watson Project is not), in which case the limit is 100 tons per year. Since the emissions from the Watson Project are not expected to exceed 250 tons per year, PSD does not apply. However, greenhouse gases (GHG) also trigger PSD review. We address GHG in a separate section of this Decision. Enforcement of NSR and PSD rules is delegated to local air districts, which are established by federal and state law. The South Coast Air Quality Management District (District or SCAQMD) has jurisdiction for NSR in Los Angeles County and its rules apply to Watson. (Ex. 200, p. 4.1-3.) The Final Determination of Compliance completed by the District did not include a PSD analysis for GHG emissions because it is currently done under federal authority, pending final adoption of a new District rule.

The project is also subject to the federal New Source Performance Standards (NSPS), which are generally delegated to the local air district; however, local emissions limitation rules are typically more restrictive than NSPS requirements. (*Id*.)

SUMMARY OF THE EVIDENCE

1. Existing Ambient Air Quality

The project is located in the city of Carson and is under the jurisdiction of the SCAQMD. **Air Quality Table 2** lists the attainment and non-attainment status of

[1] Title 42, United States Code, section 7401 et seq.

the district for each criteria pollutant for both the federal and state ambient air quality standards. (Ex. 200, p. 4.1-11.)

Air Quality Table 2
Attainment / Non-Attainment Classification
South Coast Air Quality Management District (SCAQMD)

Pollutants	Federal Classification	State Classification
Ozone	**Non-Attainment**	**Non-Attainment**
PM10	**Non-Attainment**	**Non-Attainment**
PM2.5	**Non-Attainment**	**Non-Attainment**
CO	Attainment	Attainment
NO_2	Attainment [1]	Attainment
SO_2	Attainment	Attainment

1. Attainment status for the new federal 1-hour NO_2 standard is scheduled to be determined by January 2012. The U.S. Environmental Protection Agency's (EPA's) has notified California of its intention to designate all areas of California as unclassifiable/attainment for the revised primary National Ambient Air Quality Standard (NAAQS) for NO_2.

The evidence contains a detailed analysis of Ambient Air Quality Conditions in the site vicinity for both attainment and non-attainment pollutants. (Ex. 200, pp. 4.1-9 – 4.1-17.)

2. SCAQMD Final Determination of Compliance

SCAQMD released its Final Determination of Compliance (FDOC) on March 16, 2011. The FDOC contains the permit conditions specified by SCAQMD to ensure compliance with applicable federal, state, and local air quality requirements.[2] (Ex. 202.) SCAQMD's Permit Conditions are incorporated into this Decision. However, that FDOC was issued based upon the assumption that construction of the project would commence prior to July 1, 2011. Since it did not, the project is now subject to the GHG permitting requirement under the PSD program. ~~As of the date of the evidentiary hearing in this matter, the US EPA had not yet approved into the State Implementation Plan (SIP) SCAQMD's Rule 1714, Prevention of Significant Deterioration for GHG, which was adopted by the District on December 10, 2010, nor issued a delegation agreement to the District,~~

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[2] The conditions include emissions limitations, operating limitations, offset requirements, and testing, monitoring, record keeping and reporting requirements that ensure compliance with air quality LORS.

~~which would authorize the District to issue PSD permits for GHG emission sources. (Ex. 203.) Mohsen Nazemi, Deputy Executive Officer for SCAQMD, testified at the evidentiary hearing that until Rule 1714 is approved and a delegation agreement issued, PSD permits for GHG sources would be issued by the US EPA. (11/1/11 RT 14:20–15:1.) Applicant testified that it was in the process of applying for a PSD permit but had not yet submitted the application. (11/1/11 RT 63:15–19).~~ Condition of Certification **AQ-SC6** requires the Applicant to submit to the Energy Commission Construction Project Manager (CPM) all required permits including the Authority-to-Construct permit, ensuring compliance with the PSD requirement before construction begins.

3. California Environmental Quality Act (CEQA) Requirements

In addition to reviewing the Air District's requirements, the Energy Commission also evaluates potential air quality impacts according to CEQA requirements. CEQA Guidelines identify several significance criteria to determine whether a project will: (1) conflict with or obstruct implementation of the applicable air quality plan; (2) violate any air quality standard or contribute substantially to an existing or projected air quality violation; (3) result in a cumulatively considerable net increase of any criteria pollutant for which the region is nonattainment for state or federal standards; (4) expose sensitive receptors to substantial pollutant concentrations; and (5) create objectionable odors affecting a substantial number of people. (Cal. Code Regs, tit. 14, § 15000 et seq., Appendix G.) The Guidelines note that where available, the significance criteria established by the applicable Air District may be relied upon to make a significance determination for CEQA review. (Ex. 200, p. 4.1-25.)

4. Existing Setting and Proposed Additions

The Watson Cogeneration Steam and Electric Reliability Project is a proposed expansion of a steam and electrical generating (cogeneration) facility that is located in the city of Carson in Southern California. The Watson Project will complete the original design of Watson Cogeneration Facility that has been in continuous operation for more than 20 years. The Watson Cogeneration Company (Watson) has operated four cogeneration units, since 1988, at a site within the BP Carson Refinery. The existing cogeneration facility consists of four General Electric (GE) 7EA Combustion Turbine Generators (CTG), four Heat Recovery Steam Generators (HRSG) equipped with selective catalytic reduction, and two steam turbine generators (STG). (Ex. 200, p. 4.1-17.)

The proposed Watson Project is for a fifth cogeneration train, or “fifth train,” which includes a CTG/HRSG and air pollution control system. The new cogeneration unit would increase the electric generating capacity of the facility by approximately 85 megawatts (MW), from 385 MW to 470 MW. The cogeneration unit would supply electric power and steam to the refinery and would export excess power generated to the electric utility grid. It would increase the reliability of the Watson facility, reducing the risk of refinery upset due to loss of power. The Watson Project would also ensure that the refinery’s steam demand is fully met, even when one or two of the existing CTG/HRSGs are out of service. (Ex. 200, p. 4.1-18.)

The Watson Project would operate as a base loaded cogeneration unit and is proposed to be permitted for 8,760 hours of operation per year, with an expected facility capacity factor of greater than 95 percent. The expansion Watson Project would consist of the following:

- Installation of a nominal 85 MW GE 7EA Dry Low NOx (DLN) combustion turbine with inlet fogging.
- Installation of the HRSG producing up to approximately (~) 659 Klbs steam/hr and equipped with a duct burner with up to 447.9 MMBtu/hr (high heating value [HHV]) heat input at 36ºF.
- Installation of two additional cells to the existing seven cell wet cooling tower to provide cooling and heat rejection from the new power block process.
- Installation of all required auxiliary support systems, none of which are fuel burning equipment.

The Watson Project design would incorporate air pollution emission controls designed to meet SCAQMD Best Available Control Technology (BACT) requirements. These controls would include Dry Low NOx (DLN) combustors in the CTG to limit nitrogen oxide (NOx) production, Selective Catalytic Reduction (SCR) with aqueous ammonia for additional NOx reduction in the HRSG, an oxidation catalyst to control carbon monoxide (CO) and volatile organic compounds (VOC) emissions. Fuels to be used would be pipeline specification natural gas, refinery gas, or a mix of pipeline specification natural gas and refinery gas. Low NOx burners would be incorporated into the HRSG. (Ex. 200, p. 4.1-19.)

The CTG would fire a blend of natural gas and refinery fuel gas, with the refinery fuel gas accounting for up to 35 percent by volume of fuel fired, while the duct burner in the HRSG is expected to fire mostly refinery gas. The refinery gas would be limited to a total sulfur concentration of 40 ppm on a rolling 3-hour averaging period and 30 ppm based on a rolling 24-hour averaging period. Hydrogen sulfide concentrations would be limited to 162 ppm based on a rolling 3-hour averaging period and 60 ppm based on a rolling 365 successive day average. (*Id.*)

Other emission control technologies were evaluated as part of the BACT determination. Specifically, the EMx (SCONOX) Catalyst was considered as an alternative to SCR. The EMx Catalyst offers some benefits over SCR, such as avoiding the use of ammonia. However, both SCR and EMx would be expected to achieve the proposed BACT NOx emission limit of 2.0 ppmvd @ 15 percent O2 averaged over one hour and neither would cause significant energy, economic, or environmental impacts. The concern remains regarding the long-term effectiveness of EMx as a control technology as the technology has not been demonstrated on the turbine used in this project over a long period of time. Since the Watson facility already has four identical units operating with SCR and using the more-concentrated anhydrous ammonia, the addition of a fifth unit using SCR with 30 percent aqueous ammonia would not result in the introduction of new hazards associated with SCR and aqueous ammonia and would simplify integration of the fifth unit into the existing operations. (*Id.)*

5. Determination of Direct/Indirect Impacts and Mitigation

While the emissions are the actual mass of pollutants emitted from the project, the impacts from the project result from those emitted pollutants that reach ground level. When emissions are expelled at a high temperature and velocity through the relatively tall stack, the pollutants will be significantly diluted by the time they reach ground level. The emissions from the proposed project are analyzed through the use of air dispersion models to determine the probable impacts at ground level.

The Applicant used the U.S. EPA-approved American Meteorological Society/Environment Protection Agency Regulatory Model Improvement Committee Model (AERMOD), as both a screening and refined model to estimate the direct impacts of the project’s NOx, PM10, CO, and SO_2 emissions resulting from project construction and operation. A description of the modeling analysis and its results are provided in the Application for Certification (AFC). AERMOD is a generally accepted model for this type of project, and the meteorological input data is sufficient. (Ex. 200, p. 4.1-26.)

Energy Commission staff added the Applicant's modeled impacts to the available highest ambient background concentrations recorded during the previous three years from nearby monitoring stations. Staff then compared the results with the ambient air quality standards for each respective air contaminant to determine whether the project's emission impacts would cause a new violation of the ambient air quality standards or contribute substantially to an existing violation. (Ex. 4.1-27.)

6. Construction Impacts and Mitigation

During the construction period, air emissions would be generated from the exhaust of off-road and on-road vehicles and fugitive dust from activity on unpaved surfaces and material handling. (Ex. 200, p. 4.1-27.)

The evidence shows that the project's construction emissions will not cause a new violation of the CO and SO_2 ambient air quality standards, and thus we do not find these impacts to be significant. The Applicant modeled a combination of Tier 2 and Tier 3 construction vehicle emissions and the results, as shown in **Air Quality Table 3**, indicate that construction emissions would have the potential to exceed the state 1-hour NO_2 standard if emissions occurred during maximum background conditions. The evidence, however, shows that the emissions would be less than the standard if only Tier 3 vehicles or vehicles with emissions equivalent to Tier 3 were used. Implementation of Condition of Certification **AQ-SC5** would require Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines to reduce potential impacts to less than the state 1-hour NO_2 standard.

Commission staff believes that the particulate emissions from the construction of the project create a potentially significant impact because they will contribute to existing violations of the annual and 24-hour average PM10 and the 24-hour federal PM2.5 AAQS. Those emissions can and should be mitigated to a level of insignificance.

Air Quality Table 3
Maximum Potential Construction Impacts before Mitigation (μg/m³)

POLLUTANT	Averaging Time	Modeled Impact	Background	Total Impact	Limiting Standard	Percent of Standard
NO_2	1 hour	90	264	354	339	**105 percent**
	Annual	1.5	54.1	55.6	57	98 percent
CO	1 hour	62	9,600	9662	23,000	42 percent
	8 hour	21	7,315	7336	10,000	73 percent
PM10	24 hour	4.5	131	135.5	50	**271 percent**
	Annual	0.39	45	45.39	20	**227 percent**
PM2.5	24 hour	1.5	48.5	50	35	**143 percent**
	Annual	0.22	17.5	17.72	12	**148 percent**
SO_2	1 hour	0.13	107	107.13	655	16 percent
	3-hour	0.08	107	107.08	1,300	8 percent
	24 hour	0.02	28.6	28.62	105	27 percent
	Annual	0.002	7	7.002	80	9 percent
Includes emissions due to site grading, laydown, building,						

The Applicant proposes the following mitigation measures to be implemented during project construction:

- The Applicant will have an on-site construction mitigation manager who will be responsible for the implementation and compliance of the construction mitigation program. The documentation of the ongoing implementation and compliance with the proposed construction mitigations will be provided on a periodic basis.

- All unpaved roads and disturbed areas in the Watson Project and Construction Laydown and Parking Area will be watered as frequently as necessary to control fugitive dust. The frequency of watering will be on a minimum schedule of every two hours during the daily construction activity period. Watering may be reduced or eliminated during periods of precipitation.

- On-site vehicle speeds will be limited to 5 mph on unpaved areas within the project construction site.

- The construction site entrance will be posted with visible speed limit signs.

- All construction equipment vehicle tires will be inspected and cleaned as necessary to be free of dirt prior to leaving the construction site via paved roadways.

- Gravel ramps will be provided at the tire cleaning area.

- All unpaved exits from the construction site will be graveled or treated to reduce track-out to public roadways.

- All construction vehicles will enter the construction site through the treated entrance roadways, unless an alternative route has been provided.

- Construction areas adjacent to any paved roadway will be provided with sandbags or other similar measures as specified in the construction SWPPP to prevent runoff to roadways.

- All paved roads within the construction site will be cleaned on a periodic basis (or less during periods of precipitation), to prevent the accumulation of dirt and debris.

- The first 500 feet of any public roadway exiting the construction site will be cleaned on a periodic basis (or less during periods of precipitation), using wet sweepers or air-filtered dry vacuum sweepers, when construction activity occurs or on any day when dirt or runoff from the construction site is visible on the public roadways.

- Any soil storage piles and/or disturbed areas that remain inactive for longer than 10 days will be covered, or shall be treated with appropriate dust suppressant compounds.

- All vehicles that are used to transport solid bulk material on public roadways and that have the potential to cause visible emissions will be covered, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to minimize fugitive dust emissions. A minimum freeboard height of two feet will be required on all bulk materials transport.

- Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) will be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition will remain in place until the soil is stabilized or permanently covered with vegetation.

- Disturbed areas, which are presently vegetated, will be re-vegetated as soon as practical.

To mitigate exhaust emissions from construction equipment, the Applicant is proposing the following:

- The Applicant will work with the general contractor to utilize to the extent feasible, Environmental Protection Agency (EPA)/Air Resources Board Tier 2/Tier 3 engine compliant equipment for equipment over 100 horsepower.

- Ensure periodic maintenance and inspections per the manufacturers specifications.
- Reduce idling time through equipment and construction scheduling.
- Use California low sulfur diesel fuels (<=15 ppm_w Sulfur).

(Ex. 200, pp. 4.1-28 – 4.1-30.)

In addition, Commission staff proposes that prior to the commencement of construction, the Applicant provide an Air Quality Construction Mitigation Plan (AQCMP) that specifically identifies the mitigation measures that the Applicant will employ to limit air quality impacts during construction. Staff calls for Tier 3 diesel engines for all equipment of 50 horsepower or above, rather than the 100 horsepower cut-off proposed by Watson. Conditions of Certification **AQ-SC1** through **AQ-SC5** will implement the Applicant's proposed mitigation measures and Staff's additional requirements. The evidence indicates that if the proposed project complies with these conditions, the potential for significant air quality impact from the construction of the project is less than significant.

7. Operation Impacts and Mitigation

While the construction and commissioning impacts are both relatively short lived, the operation impacts from the project will continue throughout the life of the facility. The operation impacts are thus subject to a more refined level of analysis. We now discuss the air quality impacts of project operation during normal full load conditions, including startup and shutdown events, the commissioning phase operations, and fumigation meteorological conditions.

The Applicant provided a refined modeling analysis, using the AERMOD model to quantify the potential impacts of the project during both full load operation and startup conditions. The worst case (maximum) results of this modeling analysis are shown in **Air Quality Table 4**.

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Air Quality Table 4
Refined Modeling Maximum Impacts
During Startup and Operation (μg/m^3)

POLLUTANT	AVERAGING TIME	MODELED IMPACT	BACKGROUND	TOTAL IMPACT	LIMITING STANDARD	PERCENT OF STANDARD
NO_2	1 hour	29	264	293	339	87 percent
	1-hour Federal	29	139	168	188	89 percent
	Annual	0.1	54.1	54.2	57	95 percent
CO	1 hour	31.1	9,600	9,631	23,000	42 percent
	8 hour	23.4	7,315	7,338	10,000	73 percent
PM10	24 hour	3.9	131	134.9	50	**270 percent**
	Annual	0.2	45	45.2	20	**226 percent**
PM2.5	24 hour	1.3	48.5	49.8	35	**142 percent**
	Annual	0.2	17.5	17.7	12	**148 percent**
SO_2	1 hour	0.9	107	107.9	655	16 percent
	3 hour	0.7	107	107.7	1,300	8 percent
	24 hour	0.2	28.6	28.8	105	27 percent
	Annual	0.1	7	0	80	0 percent

The modeled impact values in **Air Quality Table 4** show that during worst-case startup and full load operations, the facility will potentially contribute to the existing PM10 and PM2.5 violations. Even without the project's contribution, background values significantly exceed the ambient air quality standard. We find that any increases constitute a significant impact if not mitigated.

Although the project's emissions alone do not cause a violation of any NO_2, CO, or SO_2 ambient air quality standards, all NO_2 emissions from the facility will still need to be offset with RECLAIM Trading Credits (RTCs) to maintain district wide progress toward attainment with the ozone ambient air quality standards because NO_2 is a precursor emission to ozone formation. Similarly, the direct SO_2 impacts from the Watson Project, which do not cause a violation of the SO_2 ambient air quality standards, will need to be offset with RTCs to maintain district-wide progress toward attainment with the PM10 ambient air quality standards because SO_2 is a precursor pollutant to secondary PM10/PM2.5 formation. Implementation of Conditions of Certification **AQ-2** and **AQ-15** will ensure compliance. (Ex. 200, p. 4.1-32.)

Surface air is usually stable during the early morning hours before sunrise. During such meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed and diluted. When the sun first rises, the air at ground level is heated, resulting in turbulent vertical mixing (both rising and sinking) of air within a few hundred feet of the ground. Emissions from a stack that enter this turbulent layer of air will also be vertically mixed, bringing some of those emissions down to ground level before significant dispersion occurs and possibly causing abnormally high short term impacts. This early morning air pollution event, called fumigation, usually lasts approximately 30 to 60 minutes. The applicant used the U.S. EPA approved SCREEN3 model (version 96043) for the calculation of the project's fumigation impacts, without a shoreline assumption, since the proposed facility is a significant distance from the nearest shoreline. The Applicant's modeling analysis shows that fumigation impacts will not violate any of the one-hour standards. Staff found, and we agree, that the potential ambient air quality fumigation impacts are less than significant. (*Id.*)

The project's gaseous emissions of NO_x, SO_2, VOC and ammonia can contribute to the formation of secondary pollutants: ozone and PM10/PM2.5. The actual ammonia emissions from the Watson Project will typically be approximately 10 to 50 percent of the ammonia limit being imposed (5 ppm at 15 percent. O_2 averaged over one hour). Thus for the vast majority of the project life, the ammonia emissions are expected to be below 2 ppm. An emission of any type of pollutant at this level has a very low potential to cause a significant impact. However, the emissions of NO_x and SO_x from the Watson Project do have the potential, if left unmitigated, to contribute to higher PM2.5 levels in the region. These impacts would be significant because they would contribute to ongoing violations of the state and federal PM2.5 ambient air quality standards.

The Watson Project's air pollutant emissions impacts will be reduced by using emission control equipment and by providing emission offsets. To reduce NO_x emissions, the Applicant proposes to use dry, low-NO_x combustors and an SCR system with an ammonia injection grid.

Cooling Towers

To reduce the PM10 emissions from the cooling towers, the Applicant has committed to using wet, mechanical draft cooling towers with a drift eliminator rated at 0.001 percent and the cooling tower's water total dissolved solids will be limited to 3,575 ppmw. The SCAQMD does not address cooling towers in its permits to construct or operate. We will require that cooling tower compliance be monitored through Conditions of Certification **AQ-SC9** and **AQ-SC10**, and that mitigation measures be implemented for avoiding chronic exceedances.

<u>Combustion Turbine</u>

To reduce CO emissions, the Applicant proposes to use a combination of good combustion and maintenance practices, along with an oxidizing catalyst. The use of a clean-burning fuel (natural gas) and the efficient combustion process of the CTGs will limit VOC and PM10 emissions. The use of natural gas, low sulfur refinery gas, or a blend of natural gas and refinery gas will limit SO_2 emissions.

<u>Flue Gas Controls</u>

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed for the GE 7EA turbine. The Applicant is proposing two catalyst systems, an SCR system to reduce NO_x, and an oxidizing system to reduce CO and VOC.

<u>Emission Offsets</u>

The Applicant has or will secure sufficient offsets to satisfy SCAQMD Rule 1303 (which requires Emission Reduction Credits (ERCs)) and SCAQMD Regulation XX (which requires participation in the RECLAIM program), as well as to mitigate the project impacts under CEQA.

Implementation of the following additional measures will ensure that the project's air quality impacts are below the level of significance.

NO_x and SO_x mitigation, in the form of Regional Clean Air Initiatives Market (RECLAIM Trading Credits [RTCs]) will be achieved via the RECLAIM program either through existing holdings or through purchase.

VOC mitigation will be achieved by obtaining sufficient purchased Emission Reduction Credits (ERCs) to fully satisfy the Regulation XIII offset requirements.
PM10 emissions from the new cogeneration unit will be addressed through adoption of an emissions limit for all five cogeneration units, which is equal to the current limit for the existing four units, minus 1 lb PM10/day. The existing CEC license limits PM10 emissions from the four existing cogeneration units to 1244 lbs/day; hence the new limit will be 1243 lbs PM10/day for all five cogeneration units. Recent source testing indicates that the actual PM10 emissions from the

four existing cogeneration units are 436 lbs/day (year 2007 test) and 153 lbs/day (year 2008 test). Thus, the potential emissions of 238 lbs PM10/day from the fifth cogeneration unit would not result in exceedance of the 1,243 lbs/day limit. Implementation of SCAQMD Condition **AQ-1** will require the facility to calculate PM10 emissions from all five cogeneration units.

PM2.5 emissions from the existing Watson Cogeneration units were estimated to be 15.1 tons/year, which is well below the threshold of 100 tons/year specified in District Rule 1325. Total PM2.5 emissions for the facility with the proposed project would be 16.5 tons/year. Therefore, PM2.5 offsets would not be required for the proposed project.

CO offsets are not required since the air basin is in attainment. (Ex. 200, pp. 4.1-36 – 4.1-38.)

The evidence convinces us that implementation of the above-described measures will be sufficient to ensure that the emissions from the Watson Project do not create a significant impact to air quality. (Ex. 200, p. 4.1-41.)

8. Cumulative Impacts and Mitigation

“Cumulative impacts” are defined as “two or more individual effects which, when considered together, are considerable or which compound or increase other environmental impacts” (CEQA Guidelines, § 15355). Such impacts can be relatively minor and incremental yet still be significant because of the existing environmental background, particularly when considering other closely related past, present, and reasonably foreseeable future projects.

Criteria pollutants have impacts that are usually (though not always) cumulative by their nature. Rarely will a project itself cause a violation of a federal or state criteria pollutant standard. However, new sources contribute to violations of criteria pollutant standards because of elevated background conditions. Air districts attempt to reduce background criteria pollutant levels by adopting attainment plans, which are multi-faceted programmatic approaches to attainment. Attainment plans typically include new source review requirements that provide offsets and use Best Available Control Technology, combined with more stringent emissions controls on existing sources.

The evidence shows that the District has adopted Air Quality Management Plans (AQMPs) intended to address those criteria pollutants that are non-attainment, in

this case ozone and particulates. The SCAQMD has decided that it is most prudent to prepare a single comprehensive and integrated SIP revision that satisfies both the ozone and PM2.5 requirements. On April 28, 2011, the Air Resources Board considered revisions to the South Coast (and San Joaquin Valley) State Implementation Plans (SIPs) for PM2.5 that accounted for reductions of emissions that contribute to PM2.5 levels. The revisions were formally adopted by the ARB's Executive Officer on May 18, 2011, when Executive Order S-11-010 was signed. The April 2011 PM2.5 SIP Revisions accounted for recent regulatory actions and recessionary impacts on emissions that occurred after the South Coast (and San Joaquin Valley) PM2.5 SIPs were adopted. Those revisions accounted for the impact the recession has had on emissions and the benefits of ARB's in-use diesel truck and off-road equipment regulations. The revisions updated the PM2.5 SIP's reasonable further progress calculations, transportation conformity budgets, and ARB's rulemaking calendar.
(Ex. 200, p. 4.1-50.)

a. Ozone

The emissions of NO_x and VOC from the Watson Project do have the potential (if left unmitigated) to contribute to higher ozone levels in the region. These impacts could be cumulatively significant because they would contribute to ongoing violations of the state and federal ozone ambient air quality standards. However, emission offsets that would be provided by Watson would reduce potential impacts to a level that would be cumulatively less than significant and would not conflict with regional ozone attainment goals. (Ex. 200, p. 4.1-53.)

b. Particulate Matter

The emissions of NO_x and SO_x from the Watson Project do have the potential, if left unmitigated, to cumulatively contribute to higher PM2.5 levels in the region. These impacts could be considered significant because they would contribute to ongoing violations of the state and federal PM2.5 ambient air quality standards. However, emission offsets that would be provided by Watson would reduce potential impacts to a level that would be cumulatively less than significant. On the basis of this evidence, we conclude that the project would not cause an unmitigated cumulative impact upon regional particulate matter attainment goals. (*Id.*)

9. Compliance with LORS

The federal Prevention of Significant Deterioration (PSD) program requires major sources to obtain permits for emissions of attainment pollutants. A major source for a simple-cycle combustion turbine is defined as one whose emissions of attainment pollutants exceed 250 tons per year. Since the emissions of attainment pollutants from the Watson Project are not expected to exceed 250 tons per year, the PSD program does not apply. Thus, the SCAQMD did not issue a PSD permit as part of their Final Determination of Compliance (FDOC) for the project. (Exs. 200, p. 4.1-53; 203.)

However, new PSD requirements for greenhouse gas emissions became effective January 2, 2011 for facilities which exceed emissions thresholds for traditional PSD emissions categories and July 1, 2011 for facilities with the potential to emit greenhouse gas emissions in excess of 75,000 tons of carbon dioxide-equivalent emissions per year. The Watson Project would exceed the carbon dioxide-equivalent limit, and thus will require a PSD permit. At the evidentiary hearing, Applicant testified that it is in the process of obtaining a PSD permit. Implementation of Condition of Certification **AQ-SC-6** will ensure that this requirement is fulfilled before construction can begin.

The FDOC (Ex. 202) was issued on March 16, 2011, and demonstrates compliance will all applicable state and local LORS. The FSA contains a detailed discussion of the specific LORS. (Ex. 200, pp 4.1-53 – 4.1-62.)

On the basis of the evidence and the above discussion, we find that the project, if constructed and operated in a manner consistent with the conditions of certification set forth in this Decision, would comply with all applicable LORS pertaining to Air Quality.

We have considered the agency and public comments summarized in the FSA in preparing this Decision. (Ex. 200, p. 4.1-40.) **Mia McNulty**, representing the community as well as the Carson-Torrance branch of the NAACP, provided oral comment at the evidentiary hearing to express concerns about high levels of asthma for elderly and small children in the area, who are missing school and requiring emergency medical care. (11/1/11 RT 66:21-67:3.)

We noted above that the evidence shows that the Watson Project will have no impact on the incidence of asthma. These concerns are also addressed in the **Air Quality** and **Public Health** sections of this Decision.

FINDINGS OF FACT

1. Ambient Air Quality Standards (AAQS) have been established for seven air contaminants identified as criteria air pollutants, including sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3), nitrogen dioxide (NO_2), lead (Pb), particulate matter less than 10 microns in diameter (PM10) and particulate matter less than 2.5 microns in diameter (PM2.5).

2. Construction and operation of Watson will result in emissions of criteria air pollutants and their precursors.

3. Watson is located in Los Angeles County within the jurisdiction of the South Coast Air Quality Management District (SCAQMD).

4. SCAQMD is a nonattainment area for state and federal ozone, PM10 and PM2.5 standards.

5. Potential impacts from power plant construction-related activities will be mitigated to insignificant levels with implementation of a Construction Mitigation Plan that specifies fugitive dust control, dust plume control, diesel particulate reduction and other measures.

6. Watson has the potential to exacerbate existing violations of the 24-hour and annual PM10 and PM2.5 standards resulting in significant direct impacts to air quality in the project vicinity.

7. Project emissions of NO_x, SO_2, and VOCs, which are precursor pollutants, have the potential to result in significant secondary impacts to ambient concentrations of ozone, PM10, and PM2.5.

8. The project owner will employ the best available control technology (BACT) to limit pollutant emissions.

9. SCAQMD issued a Final Determination of Compliance on March 16, 2011 that finds Watson will comply with all applicable District rules for project operation. Because the project's emissions of attainment pollutants are below 250 tons, no PSD permit was required at that time.

10. ~~Since issuance of the FDOC, federal regulation of GHG emissions has become applicable to Watson. Accordingly, Watson is required to obtain a PSD permit.~~[Reserved]

11. The project owner will provide sufficient Emission Reduction Credits (ERCs or offsets) to offset pollutants as required by SCAQMD rules and regulations.

12. In addition to compliance with applicable SCAQMD rules, the project is subject to CEQA review, which indicates that the project will not conflict with or obstruct implementation of the applicable air quality plan; will not violate any air quality standard or contribute substantially to an existing or projected air quality violation; will not result in a cumulatively considerable net increase of any criteria pollutant for which the region is nonattainment for state or federal standards; will not expose sensitive receptors to substantial pollutant concentrations; and will not create objectionable odors affecting a substantial number of people.

CONCLUSIONS OF LAW

1. Implementation of the measures described herein will mitigate project construction and operations emissions to below the level of significance.

2. Watson's construction and operations emissions will not contribute to a cumulatively considerable adverse impact on air quality.

3. Implementation of all the conditions of certification, listed below, ensures that, if certified, Watson will be mitigated sufficiently to avoid any direct, indirect, or cumulative significant adverse impacts to air quality.

4. The Commission therefore concludes that implementation of the conditions of certification, below, will ensure that Watson conforms with all applicable laws, ordinances, regulations, and standards relating to air quality as set forth in the pertinent portions of **Appendix A** of this Decision.

CONDITIONS OF CERTIFICATION

SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
Combustion Turbines		
A63.12, .X1, .X2	AQ-1	Monthly and daily contaminant emission limit (PM10, CO, NO_x, SO_x & VOC)
S2.X1	AQ-2	Annual contaminant emissions limit (NO_x).
A99.X2	AQ-3	Relief from 2.5ppm NO_x limit during commissioning, startup and shut down. Commissioning, startup &

SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
		shutdown time limits. Limit of number of startups per year.
A99.X3	AQ-3	Relief from 2.0 ppm CO limits during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year.
A99.X4	AQ-3	Relief from 3.0 ppm CO limits during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year.
A99.X5	AQ-3	NO_x limit for interim time period of end of commissioning to continuous emission monitoring system (CEMS) certification, not to exceed 12 months.
A99.X6	AQ-3	SOx limit for interim time period of end of commissioning to continuous emission monitoring system (CEMS) certification, not to exceed 12 months.
A99.X7	AQ-3	SOx limit for interim time period of end of commissioning to continuous emission monitoring system (CEMS) certification, not to exceed 12 months.
A195.X1	AQ-4	NO_x emission limit of 2.0 ppm @ 15 percent. O2 averaged over 1-hour.
A248.X2	AQ-4	CO emission limit of 2.0 ppm @ 15 percent. O2 averaged over 1-hour.

SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
A248.X3	AQ-4	CO emission limit of 3.0 ppm @ 15 percent. O2 averaged over 1-hour.
A248.X4	AQ-4	VOC emission limit of 2.0 ppm @ 15 percent. O2 averaged over 1-hour.
A327.1	AQ-5	Relief from emission limits, under Rule 475; project may violate either the mass emission limit or concentration emission limit, but not both at the same time.
A433.X1	AQ-3	Emission limit during startup.
B61.X1	AQ-6	H2S concentration limit for refinery gas.
B61.X2	AQ-6	H2S concentration limit for fuel gas.
C1.X1	AQ-6	Limits the turbine firing rate to no more than 1069.9 MM Btu per hour (non-commissioning).
C1.X2	AQ-6	Limits the duct burner firing rate to no more than 510 MM Btu per hour (non-commissioning).
D12.X1	AQ-6	Requires the installation of a fuel flow meter.
D29.X1	AQ-7	Requires source tests for specific pollutants (NO_x, CO, SO_x, VOC, PM10, NH3) within 180 days of initial startup.
D29.X2	AQ-8	Requires source tests for ammonia (NH3); quarterly for the first year and annually thereafter.
D29.X3	AQ-7	Requires source tests for specific pollutants (SO_x and VOC) once every three years.
D29.X4	AQ-7	Requires source tests for specific pollutants (PM10) once every year.

SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
D82.X1	AQ-9	Requires the installation of CEMS for CO emissions.
D82.X2	AQ-9	Requires the installation of CEMS for NO_x emissions.
D90.X1	AQ-9	Requires the installation of CEMS for fuel gas Total Reduced Sulfur compounds.
D90.X1	AQ-9	Requires the installation of CEMS for fuel gas H2S compounds.
H23.X1	NA	Establishes the applicability of 40CFR60 Subpart KKKK for the project contaminant NO_x and SO_x.
H23.X2	NA	Establishes the applicability of 40CFR60 Subpart KKKK for the project contaminant H2S.
I296.X1	AQ-15	Prohibited from operation unless the operator hold sufficient RTCs for the CTGs.
D28.1, D29X4 & K40.X	AQ-7, -8 & -9	Source test reporting requirements.
K67.X1	AQ-10	Requires record keeping of fuel use during commissioning, prior to and after CEMs certification.
I296.X1	AQ-15	Prohibited from operation unless the operator holds sufficient RTCs.
SCR/CO Catalyst		
A99.X1	AQ-11	Relief from 5ppm NH3 limit during commissioning, startup and shut down. Commissioning, startup & shutdown time limits. Limit of number of startups per year.
A195.X1	AQ-11	Establishes the 5 ppm ammonia slip limit.
D12.X4	AQ-12	Requires a flow meter for the ammonia injection.
D12.X2	AQ-13	Requires a temperature meter at the SCR inlet.

SCAQMD Permit Conditions with Corresponding Commission Conditions of Certification

SCAQMD Permit Conditions	Energy Commission Condition of Certification	Condition Description
D12.X3	AQ-14	Requires a pressure gauge to measure the differential pressure across the SCR grid.
D12.X5	AQ-14	Requires a pressure gauge to measure the differential pressure across the CO Catalyst grid.
Ammonia Storage Tank		
C157.X	See Hazardous Material section	Requires the installation of a pressure relief valve.
E144.X	See Hazardous Material section	Requires venting of the storage tank during filling only to the vessel from which it is being filled.
K67.2	See Hazardous Material section	Requires record keeping in the manner approved by the District Executive Officer.

AQ-SC1 Air Quality Construction Mitigation Manager (AQCMM): The project owner shall designate and retain an on-site AQCMM who shall be responsible for directing and documenting compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4** and **AQ-SC5** for the entire project site construction. The on-site AQCMM may delegate responsibilities to one or more AQCMM Delegates. The AQCMM and AQCMM Delegates shall have full access to all areas of construction on the project site, and shall have the authority to stop any or all construction activities as warranted by applicable construction mitigation conditions. The AQCMM and AQCMM Delegates may have other responsibilities in addition to those described in this condition. The AQCMM shall not be terminated without written consent of the Compliance Project Manager (CPM).

Verification: At least 60 days prior to the start of ground disturbance, the project owner shall submit to the Energy Commission's Compliance Project Manager (CPM) for approval, the name, resume, qualifications, and contact information for the on-site AQCMM and all AQCMM Delegates. The AQCMM and all delegates must be approved by the CPM before the start of ground disturbance.

AQ-SC2 Air Quality Construction Mitigation Plan (AQCMP): The project owner shall provide an AQCMP, for approval, which details the steps that will be taken and the reporting requirements necessary to ensure compliance with Conditions of Certification **AQ-SC3**, **AQ-SC4,** and **AQ-SC5**.

<u>Verification:</u> At least 60 days prior to the start of any ground disturbance, the project owner shall submit the AQCMP to the CPM for approval. The AQCMP shall include effectiveness and environmental data for the proposed soil stabilizer. The CPM will notify the project owner of any necessary modifications to the plan within 30 days from the date of receipt. The AQCMP must be approved by the CPM before the start of ground disturbance.

AQ-SC3 Construction Fugitive Dust Control: The AQCMM shall submit documentation to the CPM in each Monthly Compliance Report that demonstrates compliance with the Air Quality Construction Mitigation Plan (AQCMP) mitigation measures for the purposes of minimizing fugitive dust emission creation from construction activities and preventing all fugitive dust plumes from leaving the project. The following fugitive dust mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**, and any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

A. The main access roads through the facility to the power block areas will be either paved or stabilized using soil binders, or equivalent methods, to provide a stabilized surface that is similar for the purposes of dust control to paving, that may or may not include a crushed rock (gravel or similar material with fines removed) top layer, prior to initiating construction in the main power block area, and delivery areas for operations materials (chemicals, replacement parts, etc.) will be paved prior to taking initial deliveries.

B. All unpaved construction roads and unpaved operation site roads, as they are being constructed, shall be stabilized with a non-toxic soil stabilizer or soil weighting agent that can be determined to be both as efficient or more efficient for fugitive dust control as ARB approved soil stabilizers, and shall not increase any other environmental impacts including loss of vegetation to areas beyond where the soil stabilizers are being applied for dust control. All other disturbed areas in the project construction site shall be watered as frequently as necessary during grading (consistent with **Biology** conditions of certification that address the minimization of standing water); and after active construction activities shall be stabilized with a non-toxic soil stabilizer or soil weighting agent, or alternative approved soil stabilizing methods, in order to comply with the dust mitigation objectives of Condition of Certification **AQ-SC4**. The frequency of watering can be reduced or eliminated during periods of precipitation.

C. No vehicle shall exceed 10 miles per hour on unpaved areas within the construction site, with the exception that vehicles may travel up to 25 miles per hour on stabilized unpaved roads as long as such speeds do not create visible dust emissions.

D. Visible speed limit signs shall be posted at the construction site entrances.

E. All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

F. Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

G. All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

H. All construction vehicles shall enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.

I. Construction areas adjacent to any paved roadway below the grade of the surrounding construction area or otherwise directly impacted by sediment from site drainage shall be provided with sandbags or other equivalently effective measures to prevent run-off to roadways, or other similar run-off control measures as specified in the Storm Water Pollution Prevention Plan (SWPPP), only when such SWPPP measures are necessary so that this condition does not conflict with the requirements of the SWPPP.

J. All paved roads within the construction site shall be swept daily or as needed (less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

K. At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept as needed (less during periods of precipitation) on days when construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

L. All soil storage piles and disturbed areas that remain inactive for longer than 10 days shall be covered, or shall be treated with appropriate dust suppressant compounds.

M. All vehicles that are used to transport solid bulk material on public roadways and that have potential to cause visible emissions shall be provided with a cover, or the materials shall be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard.

N. Wind erosion control techniques (such as windbreaks, water, chemical dust suppressants, and/or vegetation) shall be used on all construction areas that may be disturbed. Any windbreaks installed to comply with this condition shall remain in place until the soil is stabilized or permanently covered with vegetation.

Verification: The AQCMM shall provide the CPM a Monthly Compliance Report (**COMPLIANCE-6**) to include the following to demonstrate control of fugitive dust emissions:

A. A summary of all actions taken to maintain compliance with this condition;

B. Copies of any complaints filed with the District in relation to project construction; and

C. Any other documentation deemed necessary by the CPM or AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC4 Dust Plume Response Requirement: The AQCMM or an AQCMM Delegate shall monitor all construction activities for visible dust plumes. Observations of visible dust plumes that have the potential to be transported off the project site and within 400 feet upwind of any regularly occupied structures not owned by the project owner indicates that existing mitigation measures are not resulting in effective mitigation. The AQCMP shall include a section detailing how the additional mitigation measures will be accomplished within the time limits specified. The AQCMM or Delegate shall implement the following procedures for additional mitigation measures in the event that such visible dust plumes are observed:

Step 1: The AQCMM or Delegate shall direct more intensive application of the existing mitigation methods within 15 minutes of making such a determination.

Step 2: The AQCMM or Delegate shall direct implementation of additional methods of dust suppression if Step 1, specified above, fails to result in adequate mitigation within 30 minutes of the original determination.

Step 3: The AQCMM or Delegate shall direct a temporary shutdown of the activity causing the emissions if Step 2, specified above, fails to result in effective mitigation within one hour of the original determination. The activity shall not restart until the AQCMM or Delegate is satisfied that appropriate additional mitigation or other site conditions have changed so that visual dust plumes will not result upon restarting the shutdown source. The owner/operator may appeal to the CPM any directive from the AQCMM or Delegate to shut down an activity, if the shutdown shall go into effect within one hour of the original determination, unless overruled by the CPM before that time.

<u>Verification:</u> The AQCMM shall provide the CPM a Monthly Compliance Report (**COMPLIANCE-6**) to include:

A. a summary of all actions taken to maintain compliance with this condition;

B. copies of any complaints filed with the District in relation to project construction; and

C. any other documentation deemed necessary by the CPM and AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC5 Diesel-Fueled Engine Control: The AQCMM shall submit to the CPM, in the Monthly Compliance Report, a construction mitigation report that demonstrates compliance with the AQCMP mitigation measures for purposes of controlling diesel construction-related emissions. The following off-road diesel construction equipment mitigation measures shall be included in the Air Quality Construction Mitigation Plan (AQCMP) required by **AQ-SC2**, and any deviation from the AQCMP mitigation measures shall require prior CPM notification and approval.

A. All diesel-fueled engines used in the construction of the facility shall have clearly visible tags issued by the on-site AQCMM showing that the engine meets the conditions set forth herein.

B. All construction diesel engines with a rating of 50 hp or higher shall meet, at a minimum, the Tier 3 California Emission Standards for Off-Road Compression-Ignition Engines, as specified in California Code of Regulations, Title 13, section 2423(b)(1), unless a good faith effort to the satisfaction of the CPM that is certified by the on-site AQCMM demonstrates that such engine is not available for a particular item of equipment. All efforts to obtain diesel-powered construction equipment shall emphasize this requirement. In the event that a Tier 3 engine is not available for any off-road equipment larger than 50 hp, that equipment shall be equipped with a Tier 2 engine, or an engine that is equipped with retrofit controls to reduce exhaust emissions of nitrogen oxides (NO_x) and diesel particulate matter (DPM) to no more than Tier 2 levels unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is "not practical" for the following, as well as other, reasons.

1. There is no available retrofit control device that has been verified by either the California Air Resources Board or U.S. Environmental Protection Agency to control the engine in question to Tier 2 equivalent emission levels and the highest level of available control using retrofit or Tier 1 engines is being used for the engine in question; or
2. The construction equipment is intended to be on site for five days or less.
3. The CPM may grant relief from this requirement if the AQCMM can demonstrate a good faith effort to comply with this requirement and that compliance is not practical.

C. The use of a retrofit control device may be terminated immediately, provided that the CPM is informed within 10 working days of the termination and that a replacement for the equipment item in question meeting the controls required in item “B” occurs within 10 days of termination of the use, or if the equipment would be needed to continue working at this site for more than 15 days after the use of the retrofit control device is terminated, if one of the following conditions exists :

1. The use of the retrofit control device is excessively reducing the normal availability of the construction equipment due to increased down time for maintenance, and/or reduced power output due to an excessive increase in back pressure.
2. The retrofit control device is causing or is reasonably expected to cause engine damage.
3. The retrofit control device is causing or is reasonably expected to cause a substantial risk to workers or the public.
4. Any other seriously detrimental cause which has the approval of the CPM prior to implementation of the termination.

D. All heavy earth-moving equipment and heavy duty construction-related trucks with engines meeting the requirements of (B) above shall be properly maintained and the engines tuned to the engine manufacturer’s specifications.

E. All diesel heavy construction equipment shall not idle for more than five minutes. Vehicles that need to idle as part of their normal operation (such as concrete trucks) are exempted from this requirement.

F. Construction equipment will employ electric motors when feasible.

<u>Verification:</u> The AQCMM shall include in the Monthly Compliance Report the following to demonstrate control of diesel construction-related emissions:

A. A summary of all actions taken to control diesel construction related emissions;

B. A list of all heavy equipment used on site during that month, including the owner of that equipment and a letter from each owner indicating that equipment has been properly maintained; and

C. Any other documentation deemed necessary by the CPM, and the AQCMM to verify compliance with this condition. Such information may be provided via electronic format or disk at the project owner's discretion.

AQ-SC6 The project owner shall provide the CPM copies of all District and/or US EPA-issued Authority-to-Construct (ATC) and Permit-to-Operate (PTO) documents for the facility. The ATC documents shall be submitted prior to the commencement of construction. The project owner shall submit to the CPM for review and approval any modification proposed by the project owner to any project air permit. The project owner shall submit to the CPM any modification to any permit proposed by the District or U.S. Environmental Protection Agency (U.S. EPA), and any revised permit issued by the District or U.S. EPA, for the project.

Verification: The project owner shall submit any ATC, PTO, and proposed air permit modifications to the CPM within five working days of its submittal either by 1) the project owner to an agency, or 2) receipt of proposed modifications from an agency. The project owner shall submit all modified air permits to the CPM within 15 days of receipt.

AQ-SC7 The project owner shall provide emission reduction credits to offset combined-cycle turbine exhaust NO_x, VOC and SO_x emissions in the form and amount required by the District. RECLAIM Trading Credits (RTCs) shall be provided for NO_x and SO_x as is necessary to demonstrate compliance with Condition of Certification **AQ-15**.

Emission reduction credits (ERCs) shall be provided for VOC (187 lb/day, includes offset ratio of 1.2:1.0). The project owner shall surrender the ERCs for VOC from among those that are listed in the table below or a modified list, as allowed by this condition. If additional ERCs are submitted, the project owner shall submit an updated table including the additional ERCs to the CPM. The project owner shall request CPM approval for any substitutions, modifications, or additions of credits listed.

The CPM, in consultation with the District, may approve any such change to the ERC list provided that the project remains in compliance with all applicable laws, ordinances, regulations, and standards, the requested change(s) will not cause the project to result in a significant environmental impact, and the SCAQMD confirms that each requested change is consistent with applicable federal and state laws and regulations.

The project owner shall request from the SCAQMD a report of the NSR Ledger Account for the project after the SCAQMD has issued the Permit to Construct. This report is to specifically identify the ERCs used to offset the project emissions.

Certificate Number	Amount (lbs/day)	Pollutant
AQ007588	4	VOC
AQ008748	7	VOC
AQ010814	50	VOC
To be determined (TBD)	126	VOC

<u>Verification:</u> The project owner shall submit to the CPM the NSR Ledger Account, showing that all project offset requirements have been met, 15 days prior to initiating construction for Priority Reserve credits, and 30 days prior to turbine first fire for traditional ERCs. Prior to commencement of construction, the project owner shall obtain sufficient Reclaim Trading Credits (RTCs) to satisfy the District's requirements for the first year of operation as prescribed in Condition of Certification **AQ-15**. If the CPM approves a substitution or modification to the list of ERCs, the CPM shall file a statement of the approval with the project owner and Energy Commission's docket for Watson. The CPM shall maintain an updated list of approved ERCs for the project.

AQ-SC8 The project owner shall submit to the CPM Quarterly Operation Reports, following the end of each calendar quarter, that include operational and emissions information as necessary to demonstrate compliance with the conditions of certification herein. The Quarterly Operation Report will specifically note or highlight incidences of noncompliance.

<u>Verification:</u> The project owner shall submit the Quarterly Operation Reports to the CPM and APCO no later than 30 days following the end of each calendar quarter.

AQ-SC9 The project owner shall perform quarterly cooling tower recirculating water quality testing, or shall provide for continuous monitoring of conductivity as an indicator, for total dissolved solids content.

<u>Verification:</u> The project owner shall submit to the CPM cooling tower recirculating water quality tests or a summary of continuous monitoring results and daily recirculating water flow in the Quarterly Operation Report (**AQ-SC8**). If the project owner uses continuous monitoring of conductivity as an indicator for total dissolved solids content, the project owner shall submit data supporting the calibration of the conductivity meter and the correlation with total dissolved solids content at least once each year ~~in a Quarterly Operation Report~~ (**AQ-SC8**).

AQ-SC10 The new cooling tower cells daily PM10 emissions shall be limited to 7.92 lb/day in total for both cooling tower cells. The cooling towers shall be equipped with a drift eliminator to control the drift fraction to 0.001 percent of the circulating water flow. Total dissolved solids (TDS) shall be limited to 3,575 ppmw. The project owner shall estimate daily PM10 emissions from the cooling towers using the water quality testing data or continuous monitoring data and daily circulating water flow data ~~collected on a quarterly basis~~. Compliance with the cooling tower PM10 emission limit shall be demonstrated as follows:

PM10 = cooling water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate.

Verification: The project owner shall submit to the CPM daily cooling tower PM10 emission estimates in the Quarterly Operation Report (**AQ-SC8**).

The following conditions of certification incorporate District conditions as required in the Determination of Compliance. Refer to **Air Quality Table 23** above to relate these conditions to the District's conditions.

AQ-1 The project owner shall limit the emissions from the new gas fired combustion turbine train exhaust stack as follows:

Contaminant	Emissions Limit
PM10	1,243 lbs in any one day (total combined emissions from all 5 Watson Cogeneration Units)
VOC	3,095 lbs in any one month

The operator shall initially calculate the daily PM10 emissions using daily fuel use data for each combustion unit, the higher heating value of the fuel burned in each combustion unit, and the following emissions factors: 0.00393 lbs PM10 / MMBTU for Natural Gas and 0.00402 lbs PM10 / MMBTU for Refinery Gas.

The PM10 emission factor for Cogeneration Units 1, 2, 3, 4, and 5 shall be revised annually based on results of individual PM10 source tests performed as specified in permit conditions D28.1 and D29X4 (**AQ-7**). The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu for all valid source test runs during each individual source test.

For purposes of this condition, limits shall be based on the total combined emissions from the combustion turbine and duct burner. The project owner shall calculate emissions by using monthly fuel use data and an emissions factor of 2.64 lbs VOC/MMscf for natural gas.

For Refinery Gas, the following formula should be used to calculate emissions factors, in units of lbs VOC/MMscf: 2.94E-7 x Fd-Factor x GCV_v; where the Fd-Factor is the ratio of the volume of products of combustion to the fuel heat content, in units of dscf/MMBtu, and GCV_v is gross fuel calorific value, in units of Btu/scf. Monthly averages of Fd-Factor and GCV_v for Refinery Gas shall be used in this calculation.

For the purpose of this condition, the term "normal operations" is defined as the turbine is able to supply electrical energy to the power grid.

Verification: The project owner shall submit all emission calculations, fuel use, CEM records and a summary demonstrating compliance of all emission limits stated in this condition for approval to the CPM on a quarterly basis in the quarterly emissions report required in (**AQ-SC8**).

AQ-2 The project owner/operator shall not produce emissions of oxides of nitrogen from the ~~facility~~ proposed project (fifth train) that exceed ~~the RECLAIM Trading Credits holdings of~~ 39.9 tons~~/yr~~ in any 12-month period, determined monthly based on total emissions over the previous 12-month period. ~~required in Condition of Certification **AQ-15** within a calendar year.~~

Verification: The project owner/operator shall submit to the CPM no later than 60 days following the end of each calendar year, the SCAQMD required (via Rule 2004) Quarterly Certification of Emissions (or equivalent) for each quarter and the Annual Permit Emissions Program report (or equivalent) as prescribed by the SCAQMD Executive Officer.

AQ-3 The commissioning period shall not exceed 550 hours. The time for cold startup shall not exceed 3 hours for each startup. The time for warm startup shall not exceed 1 hour. The time for shutdown shall not exceed 1 hour. The turbine shall be limited to 4 cold startups per year, 24 warm startups per year, and 29 shutdowns per year.

The 5 ppm NH3 limit, 2 ppm NO_x emission limit 2 ppm CO emission limit, and 3 ppm CO emission limit shall not apply during commissioning, start-up, and shutdown periods.

The 44 LBS/MMCF NO_x emission limit, 0.80 LBS/MMCF SOx emission limit and 5.07 LBS/MMCF SO_x emission limit shall only apply during the interim reporting period to report RECLAIM emissions.

The operator shall comply at all times with the 2.0 ppm 1 hour BACT limit for NO_x, except as defined in condition A99.X2, (**AQ-3,** this condition) and for the following operating scenarios:

Operating Scenario	Maximum Hourly Emission Limit	Operational Limit
Cold Start	175.0	NO_x emissions shall not exceed 211.24 lbs per cold start-up.
Warm Start	21.32	NO_x emissions shall not exceed 21.32 lbs per warm start-up.
Shutdown	12.85	NO_x emissions shall not exceed 12.85 lbs per shutdown.

The interim reporting period shall not exceed 12 months from the initial startup date. Written records of commissioning, start-ups and shutdowns shall be kept and made available to SCAQMD and submitted to the CPM for approval.

The project owner/operator shall complete construction and the project shall be fully operational within three years of the issuance of the permit to construct from the SCAQMD.

Verification: The project owner shall provide the SCAQMD and the CPM with the written notification of the initial start-up date no later than 60 days prior to the startup date. The project owner shall submit, commencing one month from the time of gas turbine first fire, a monthly commissioning status report throughout the duration of the commissioning phase that demonstrates compliance with this condition and the emission limits of Condition **AQ-13**. The monthly commissioning status report shall include criteria pollutant emission estimates for each commissioning activity and total commissioning emission estimates. The monthly commissioning status report shall be submitted to the CPM until the report includes the completion of the initial commissioning activities. The project owner shall provide start-up and shutdown occurrence and duration data as part as part of the Quarterly Operation Report (**AQ-SC8**) including records of all aborted turbine startups. The project owner shall make the site available for inspection of the commissioning and startup/shutdown records by representatives of the District, CARB and the Commission.

AQ-4 The new combustion turbine stack shall have the following emission limitations.

- 2.0 PPM NO_x emission averaged over 60 minutes at 15 percent. oxygen, dry basis.
- 2.0 ppm CO emission averaged over 60 minutes at 15 percent. oxygen, dry basis.
- 3.0 ppm CO emission averaged over 180 minutes at 15 percent. oxygen, dry basis.

- 2.0 ppm VOC emission averaged over 60 minutes at 15 percent. oxygen, dry basis.

- 5.0 ppm NH_3 emission averaged over 60 minutes at 15 percent. oxygen, dry basis.

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC8**.

AQ-5 The project owner may exceed either the combustion contaminant mass limit of 11 lbs/hour or concentration emission limit of 0.01 gr/scf calculated at 3 percent oxygen, dry basis averaged over 15 consecutive minutes, but not both limits at the same time.

Verification: The project owner shall submit to the CPM for approval all emissions and emission calculations on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC8**.

AQ-6 The operator shall not use refinery gas containing the following specified compounds:

Compound	ppm by volume
Total Reduced Sulfur (calculated as H2S) greater than	40
Total Reduced Sulfur (calculated as H2S) greater than	30

The 40 ppm limit shall be based on a rolling 3-hour averaging period. The 30 ppm limit shall be based on a rolling 24-hour averaging period.

Refinery gas is defined as a mixture of refinery fuel gas, produced within the refinery that may be mixed with natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), in order to balance heat content of the fuel gas mixture, (formed at a point upstream of the sampling location for Total Reduced Sulfur concentration). The natural gas component of the fuel gas mixture shall not exceed 50 percent of the refinery gas total, by Higher Heating Value (HHV) content.

The operator shall not use ~~fuel~~ refinery gas containing the following specified compounds:

Compound	ppm by volume
H2S greater than	162
H2S greater than	60

The 162 ppm limit shall be based on a rolling 3-hour averaging period. The 60 ppm limit shall be based on a rolling 365 successive day average.

The operator shall limit the CTG firing rate to no more than 1069.9 MM Btu per hour. The operator shall limit the HRSG duct burner firing rate to no more than 510 MM Btu per hour.

For the purpose of this condition, firing rate shall be defined as energy or heat input of natural gas and refinery gas to the equipment combustion chamber based on the higher heating value (HHV) of the natural gas and refinery gas used.

The refinery gas input to the turbine in any hour shall not exceed 35 percent of the total volume of gas combusted. Refinery gas shall be as defined in condition B61.X1 (Condition **AQ-6**).

The operator shall install and maintain a(n) continuous monitoring system to accurately indicate the energy being supplied to the gas turbine by measurement of Higher Heating Value (HHV) of refinery fuel gas.

The operator shall also install and maintain a device to continuously record the parameter being measured. For the purpose of this condition, continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour. The purpose of this condition is to demonstrate compliance with the limitation of refinery fuel gas, as having natural gas accounting for no more than 50 percent of the Higher Heating Value (HHV) of the mixture.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. The operator shall install and maintain a fuel flow meter and recorder to accurately indicate and record the fuel usage being supplied to the turbine.

Verification: The project owner shall submit to the CPM for approval all fuel usage records on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC8**.

AQ-7 The project owner shall conduct an initial source test for NO_x, CO, SOx, VOC, NH_3, PM10 and PM2.5 and periodic source test every three years thereafter for NO_x, CO, SO_x, VOC, PM10 and PM2.5 of the new turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the SCAQMD and the CPM 45 days prior to the proposed source test date for approval. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of

SCAQMD Rule 304, and a description of all sampling and analytical procedures.

- The initial source test shall be conducted within 90 days after achieving maximum production rate, but no later than 180 days following the date of first fire.
- The SCAQMD and CPM shall be notified at least 10 days prior to the date and time of the source test.
- The source test shall be conducted with the gas turbine operating under maximum, average and minimum loads.
- The source test shall be conducted to determine the oxygen levels in the exhaust.
- The source test shall measure the fuel flow rate, the flue gas flow rate and the turbine generating output in MW.
- The source test shall be conducted for the pollutants listed using the methods**,** averaging times**,** and test locations indicated and as approved by the CPM as follows:

Source Test Requirements

Pollutant	Method	Averaging Time	Test Location
NO_x	SCAQMD Method 100.1	1 hour	Outlet of SCR
CO	SCAQMD Method 100.1	1 hour	Outlet of SCR
SO_x	District Method 307.91	N/A	Fuel Sample
VOC	District Method 25.3 or TO-12	1 hour	Outlet of SCR
PM10	District Method 5	4 hours	Outlet of SCR
PM2.5	EPA Methods 201A and 202	4 hours	Outlet of SCR
Ammonia	SCAQMD Method ~~5.3 and~~ 207.1 or U.S. EPA Method 17.	1 hour	Outlet of SCR

- The source test results shall be submitted to the SCAQMD and the CPM no later than 60 days after the source test was conducted.

- All emission data is to be expressed in the following units:

  1. ppmv corrected to 15 percent. oxygen dry basis,
  2. pounds per hour,
  3. pounds per million cubic feet of fuel burned and
  4. additionally, for PM10 only, grains per dry standard cubic feet of ~~fuel burned~~ gas exhausted.

- Exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute and actual cubic feet per minute.

- All moisture concentrations shall be expressed in terms of percent corrected to 15 percent oxygen.

- For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence of the AQMD, CARB, EPA and the Energy Commission.

Verification: The project owner shall submit the proposed protocol for the initial source tests 45 days prior to the proposed source test date to both the SCAQMD and CPM for approval. The project owner shall submit source test results no later than 60 days following the source test date to both the SCAQMD and CPM. The project owner shall notify the SCAQMD and CPM no later than 10 days prior to the proposed initial source test date and time.

AQ-8 The project owner shall conduct source testing of the turbine exhaust stack in accordance with the following requirements:

- The project owner shall submit a source test protocol to the SCAQMD and the CPM for approval no later than 45 days prior to the proposed source test date. The protocol shall include the proposed operating conditions of the gas turbine, the identity of the testing lab, a statement from the lab certifying that it meets the criteria of SCAQMD Rule 304, and a description of all sampling and analytical procedures.

- Source testing for ammonia slip only shall be conducted quarterly for the first 12 months of operation and annually thereafter.

- NO_x concentrations as determined by CEMS shall be simultaneously recorded during the ammonia test. If the NO_x CEMS is inoperable, a test shall be conducted to determine the NO_x emission by using SCAQMD Method 100.1 measured over a 60 minute time period.

- Source testing shall be conducted to determine the ammonia emissions from the new turbine exhaust stack using SCAQMD Method ~~5.3 and~~ 207.1 or U.S. EPA Method 17 measured over a 1 hour averaging period at the outlet of the SCR.

- The SCAQMD and CPM shall be notified of the date and time of the source testing at least 7 days prior to the test.
- The source test shall be conducted and the results submitted to the SCAQMD and CPM within ~~45~~ 60 days after the test date.
- Source testing shall measure the fuel flow rate, the flue gas flow rate and the gas turbine generating output.
- The test shall be conducted when the equipment is operating at 80 percent load or greater.
- If the turbine is not in operation during one quarter, then no testing is required during that quarter.
- All emission data is to be expressed in the following units:

  1. ppmv corrected to 15 percent oxygen,
  2. pounds per hour,
  3. pounds per million cubic feet of fuel burned.

Verification: The project owner shall submit the proposed protocol for the source tests 45 days prior to the proposed source test date to both the SCAQMD and CPM for approval. The project owner shall notify the SCAQMD and CPM no later than seven days prior to the proposed source test date and time. The project owner shall submit source test results no later than 60 days following the source test date to both the SCAQMD and CPM.

AQ-9 The project owner shall install and maintain a CEMS in the exhaust stack of the combustion turbine train to measure the following parameters:

- NO_x, SO_x ~~concentration in ppmv~~ and CO concentrations in ppmv.
- Concentrations shall be corrected to 15 percent oxygen on a dry basis.
- The CEMS will convert the actual CO concentrations to mass emission rates (lb/hr) and record the hourly emission rates on a continuous basis.
- The CEMS shall be installed and operated to measure CO concentration over a one and three hour averaging time periods.
- The CEMS shall be installed and operated in accordance with an approved SCAQMD Rule 218 CEMS plan application and the requirements of Rule 2012.
- The CO CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine.

- The NO_x and SO_x CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine.

During the interim period between the initial start-up and the provisional certification date of the CEMS, the project owner shall comply with the monitoring requirements of Rule 2012 (h)(2) and Rule 2012 (h)(3). Within two weeks of the turbine start-up date, the project owner shall provide written notification to the SCAQMD of the exact date of start-up.

Verification: Within 30 days of certification, the project owner shall notify the CPM of the completion of the certification process for the CEMS.

AQ-10 The project owner shall keep records in a manner approved by the SCAQMD for the following items:

- Commissioning hours, type of control, and fuel use
- Date and time of each start-up and shutdown
- In addition to the requirements of a certified CEMS, fuel use records shall be kept during and after the commissioning period and prior to CEMS certification
- Minute by minute data (NO_x and O_2 concentration and fuel flow at a minimum) for each turbine start-up.

Verification: The project owner shall submit to the CPM for approval all fuel usage records on a quarterly basis as part of the quarterly emissions report of Condition of Certification **AQ-SC8**.

AQ-11 The owner/operator shall determine the hourly ammonia slip emissions from the exhaust stack via both the following formulas:

SCAQMD Requirement:

- NH3 (ppmv) = [a-(b*c~~*1.2~~)/1E6]*1E6/b

Where:

a = NH3 injection rate (lb/hr) / 17(lb/lbmol),

b = dry exhaust flow rate ~~(scf/hr)~~ lb/hr) / ~~385.5 (scf/lbmol),~~29 (lb/lbmole), and

c = change in measured NOx across the SCR (ppmvd at 15 percent O2)

The above described ammonia slip calculation procedure shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia for the District.

Energy Commission Requirement:

- NH3 (ppmv @ 15 percent. O2) = ((a-b*(c/1E6))*1E6/b)*d

Where:

a = NH3 injection rate (lb/hr)/17(lb/lbmol,

b = dry exhaust gas flow rate (lb/hr)/ (29(lb/lbmol), or

b = dry exhaust flow rate (scf/hr) / 385.5 (scf/lbmol),

c = change in measured NOx concentration ppmv corrected to 15 percent O2 across catalyst, and

d = correction factor.

The correction factor shall be derived through compliance testing by comparing the measured and calculated ammonia slip. The correction factor shall be reviewed and approved by the CPM on at least an annual basis. The correction factor may rely on previous compliance source test results or other comparable analysis as the CPM finds the situation warrants. The above described ammonia slip calculation procedure shall be used for Energy Commission compliance determination for the ammonia slip limit as prescribed in Condition of Certification **AQ-4** and reported to the CPM on a quarterly basis as prescribed in Condition of Certification **AQ-SC8**.

The 5 ppm NH3 limit(s) shall not apply during commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 550 hours. The time for cold startup shall not exceed three hours for each startup. The time for warm startup shall not exceed one hour. The time for shutdown shall not exceed one hour. The turbine shall be limited to four cold startups per year, ~~12~~ 24 warm startups per year, and ~~16~~ 29 shutdowns per year.

An exceedance of the ammonia slip limit as demonstrated by the above Energy Commission formula shall not in and of itself constitute a violation of the limit. An exceedance of the ammonia slip limit shall not exceed six hours in duration. In the event of an exceedance of the ammonia slip limit exceeding six hours duration, the project owner shall notify the CPM within 72 hours of the occurrence. This notification must include, but is not limited to: the date and time of the exceedance, duration of the exceedance, estimated emissions as a result of the exceedance, the suspected cause of the exceedance and the corrective action taken or planned. Exceedances of the ammonia limit that are less than or equal to six hours in duration shall be noted in a specific section within the Quarterly Report (**AQ-SC8**). This section shall include, but is not limited to: the date and time of the exceedance, duration of the exceedance, and the estimated emissions as a result of the exceedance. Exceedances shall be deemed chronic if they total more than 10 percent of the operation. Chronic exceedances must be investigated and redressed in a timely manner and in conjunction with the CPM through the cooperative development of a compliance plan. The compliance plan shall be developed to bring the project back into compliance first and foremost and shall secondly endeavor to do so in a feasible and timely manner, but shall not be limited in scope.

The owner/operator shall maintain compliance with the ammonia slip limit, redress exceedances of the ammonia slip limit in a timely manner, and avoid chronic exceedances of the ammonia slip limit. Exceedances shall be deemed a violation of the ammonia slip limit if they are not properly redressed as prescribed herein.

The owner/operator shall install a NO_x analyzer to measure the SCR inlet NO_x ppm accurate to within +/- 5 percent calibrated at least once every 12 months.

<u>Verification:</u> The project owner shall include ammonia slip concentrations averaged on an hourly basis calculated via both protocols provided as part of the Quarterly Operational Report required in Condition of Certification **AQ-SC8**. The project owner shall submit all calibration results performed to the CPM within 60 days of the calibration date. The project owner shall submit to the CPM for approval a proposed correction factor to be used in the Energy Commission formula at least once a year but not to exceed 180 days following the completion of the annual ammonia compliance source test. Exceedances of the ammonia limit shall be reported as prescribed herein. Chronic exceedances of the ammonia slip limit shall be identified by the project owner and confirmed by the CPM within 60 days of the fourth quarter Quarterly Operational Report (**AQ-SC8**) being submitted to the CPM. If a chronic exceedance is identified and confirmed, the project owner shall work in conjunction with the CPM to develop a reasonable compliance plan to investigate and redress the chronic exceedance of the ammonia slip limit within 60 days of the above confirmation.

AQ-12 The operator shall install and maintain an ammonia injection flow meter and recorder to accurately indicate and record the ammonia injection flow rate being supplied the turbine. The device or gauge shall be accurate to within plus or minus five percent and shall be calibrated once every 12 months.

Continuously recording is defined for this condition as at least once every hour and is based on the average of the continuous monitoring for that hour.

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate device has been installed and is functioning properly. The project owner shall submit annual calibration results within 30 days of their successful completion.

AQ-13 The operator shall install and maintain a temperature gauge and recorder to accurately indicate and record the temperature in the exhaust at the inlet of the SCR reactor. The gauge shall be accurate to within plus or minus five percent and shall be calibrated once every 12 months. The catalyst temperature range shall remain between 740 degree F and 840 degree F while the SCR reactor is being used to reduce NO_x emissions. Ammonia injection is not required if the inlet SCR temperature falls below 500 F, not to exceed 3 hours during startup.

Continuously recording is defined for this condition as at least once every hour and is based on the average of the continuous monitoring for that hour.

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate device has been installed and is functioning properly. The project owner shall submit annual calibration results within 30 days of their successful completion.

AQ-14 The operator shall install and maintain a pressure gauge and recorder to accurately indicate and record the pressure differential across the SCR catalyst bed in inches of water column. The gauge shall be accurate to within plus or minus five percent and shall be calibrated once every 12 months. The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the CO catalyst reactor in inches water column.

Continuously recording is defined for this condition as at least once every month and is based on the average of the continuous monitoring for that month.

Verification: The project owner shall submit to the CPM no less than 30 days after installation, a written statement by a California registered Professional Engineer stating that said engineer has reviewed the as-built-designs or inspected the identified equipment and certifies that the appropriate device has been installed and is functioning properly. The project owner shall submit annual calibration results within 30 days of their successful completion.

AQ-15 The project equipment shall not be operated unless the project owner demonstrates to the SCAQMD Executive Officer that the facility holds sufficient Reclaim Trading Credits (RTCs) to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the project owner demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase. The project owner shall submit all such information to the CPM for approval.

To comply with this condition, the operator shall, prior to the 1st compliance year hold a minimum NO_x RTCs of 99,850 lbs/yr and a minimum SOx RTCs of 31,050 lbs/yr. This condition shall apply during the first 12 months of operation, commencing with the initial operation of the gas turbine/heat recovery steam generator.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION
FOR THE *WATSON COGENERATION STEAM AND ELECTRIC RELIABILITY PROJECT*

DOCKET NO. 09-AFC-1
PROOF OF SERVICE LIST
(Revised 3/21/12)

APPLICANT

Ross Metersky
BP Products North America, Inc.
700 Louisiana Street, 12th Floor
Houston, Texas 77002
ross.metersky@bp.com

APPLICANT'S CONSULTANTS

URS Corporation
Cynthia H. Fischer
8181 East Tufts Avenue
Denver, Colorado 80237
cindy.fischer@urs.com

COUNSEL FOR APPLICANT

Chris Ellison
Ellison Schneider and Harris LLP
2600 Capitol Avenue, Suite 400
Sacramento, CA 95816
cte@eslawfirm.com

INTERESTED AGENCIES

California ISO
e-recipient@caiso.com

INTERVENORS

California Unions for Reliable Energy (CURE)
c/o: Tanya A. Gulesserian
Marc D. Joseph
Adams Broadwell Joseph & Cardozo
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080
tgulesserian@adamsbroadwell.com

ENERGY COMMISSION – DECISIONMAKERS

CARLA PETERMAN
Commissioner and Presiding Member
cpeterma@energy.ca.gov

KAREN DOUGLAS
Commissioner and Associate Member
e-mail service preferred
kldougla@energy. ca.gov

Jim Bartridge
Presiding Member's Advisor
jbartrid@energy. ca.gov

Galen Lemei
Associate Member's Advisor
e-mail service preferred
glemei@energy. ca.gov

Raoul Renaud
Hearing Adviser
rrenaud@energy. ca.gov

ENERGY COMMISSION STAFF

*Felicia Miller
Project Manager
fmiller@energy.ca.gov

Jeff Ogata
Staff Counsel
e-mail service preferred
jogata@energy.ca.gov

Eileen Allen
Commissioners' Technical Adviser for Facility Siting
e-mail service preferred
eallen@energy.ca.gov

ENERGY COMMISSION – PUBLIC ADVISER

Jennifer Jennings
Public Adviser's Office
e-mail service preferred
publicadviser@energy.state.ca.us

*indicates change

<u>DECLARATION OF SERVICE</u>

I, Chester Hong, declare that on March 21, 2012, I served and filed a copy of the attached Supplemental Staff Filing Regarding Additional Staff-Proposed Errata, dated March 21, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at: www.energy.ca.gov/sitingcases/watson/index.html.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(*Check all that Apply*)

For service to all other parties:

__X__ Served electronically to all e-mail addresses on the Proof of Service list;

__X__ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "e-mail preferred."

AND

For filing with the Docket Unit at the Energy Commission:

____ by sending one electronic copy to the e-mail address below (preferred method); *OR*

__X__ by electronically filing via e-mail to:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 09-AFC-1
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
Sacramento, CA 95814
mlevy@energy.state.ca.us

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

/s/
CHESTER HONG